UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	))	**Docket No. _______**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS FOR INTERCHANGE SCHEDULING AND COORDINATION

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits the following five proposed Reliability Standards for Commission approval:

- INT-004-3 – Dynamic Transfers;
- INT-006-4 – Evaluation of Interchange Transactions;
- INT-009-2 – Implementation of Interchange;
- INT-010-2 – Interchange Initiation and Modification for Reliability; and
- INT-011-1 – Intra-Balancing Authority Transaction Identification.

As explained below, NERC proposes to retire five currently-effective Reliability Standards and proposes ten revised definitions and four new definitions for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*.[4] The Interchange Scheduling and Coordination

1 16 U.S.C. § 824o (2006).

2 18 C.F.R. § 39.5 (2013).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 *Available at*: http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf. ("NERC Glossary").

("INT") group of Reliability Standards addresses interchange transactions, which occur when electricity is transmitted from a seller to a buyer across the power grid.

NERC requests that the Commission approve the proposed Reliability Standards and definitions (**Exhibit A**) and find that the proposed Reliability Standards and definitions are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[5] NERC also requests approval of the associated implementation plan (**Exhibit B**), Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit G**), and retirement of the currently effective Reliability Standards and definitions as detailed in this petition.

As required by Section 39.5(a)[6] of the Commission's regulations, this petition presents the technical basis and purpose of the proposed Reliability Standards, a summary of the development history (**Exhibit H**), and a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672[7] (**Exhibit C**). The proposed Reliability Standards and definitions were approved by the NERC Board of Trustees on February 6, 2014.

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5 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

6 18 C.F.R. § 39.5(a) (2013).

7 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

I. EXECUTIVE SUMMARY

Interchange refers to energy transfers that cross Balancing Authority boundaries.[8] The proposed Reliability Standards improve reliability by making transactions more apparent for reliability assessments and by clarifying which functional entities perform Interchange Authority tasks. Collectively, the proposed five Reliability Standards also consolidate this body of standards. The currently enforceable set of Interchange Scheduling and Coordination Reliability Standards consists of nine Reliability Standards with thirteen requirements. NERC is proposing to revise four of the currently-effective Reliability Standards and is proposing one new Reliability Standard, INT-011-1 – Intra-Balancing Authority Transaction Identification, resulting in a set of five proposed Reliability Standards consisting of fourteen requirements.[9]

A. Proposed Reliability Standards

NERC proposes the following five Reliability Standards for approval:[10]

Proposed Reliability Standards

- INT-004-3 – Dynamic Transfers;
- INT-006-4 – Evaluation of Interchange Transactions;
- INT-009-2 – Implementation of Interchange;
- INT-010-2 – Interchange Initiation and Modification for Reliability; and
- INT-011-1 – Intra-Balancing Authority Transaction Identification.

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8 *See NERC Glossary*, available at: http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

9 These revisions and retirements are supported by the recommendation of the Independent Expert Review Panel to retire 85% of the requirements in the Interchange Scheduling and Coordination body of Reliability Standards. *Available at*: http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf.

10 The currently-effective versions of these Reliability Standards would be retired upon Commission approval of the proposed Reliability Standards (INT-004-2; INT-006-3; INT-009-1; INT-010-1).

NERC proposes to retire the following five currently-effective Reliability Standards in entirety:

Proposed Retirement of Reliability Standards

- INT-001-3 – Interchange Information;
- INT-003-3 – Interchange Transaction Implementation;
- INT-005-3 – Interchange Authority Distributes Arranged Interchange;
- INT-007-1– Interchange Confirmation; and
- INT-008-3—Interchange Authority Distributes Status.

B. Proposed Definitions

NERC submits accompanying proposed revisions to ten definitions in the NERC Glossary of Terms and proposes four new definitions, as follows:

Proposed Revised Definitions:

- Adjacent Balancing Authority
- Arranged Interchange
- Confirmed Interchange
- Dynamic Interchange Schedule or Dynamic Schedule
- Intermediate Balancing Authority
- Operational Planning Analysis
- Pseudo-Tie
- Request for Interchange
- Sink Balancing Authority
- Source Balancing Authority

Proposed New Definitions:

- Attaining Balancing Authority
- Composite Confirmed Interchange
- Native Balancing Authority
- Reliability Adjustment Arranged Interchange

The proposed revisions to the defined terms “Adjacent Balancing Authority,” “Intermediate Balancing Authority,” “Sink Balancing Authority,” “Source Balancing Authority,” and the proposed new definitions of "Attaining Balancing Authority" and "Native Balancing Authority" are necessary to define the various Balancing Authorities involved in the implementation of Interchange and their relationships with respect to Interchange. Each of the proposed revised and new definitions is explained below in greater detail.

C. Technical Background: Interchange Transactions

An Interchange Transaction refers to an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries. Provided below is an overview of the parties involved in Interchange Transactions and the mechanics of those transactions.

1. <u>Parties Involved in Interchange Transactions</u>

An Interchange Transaction begins with a Request for Interchange, which is a collection of data for the purpose of implementing an energy transfer between one or more Balancing Authorities. The "Source Balancing Authority" is the Balancing Authority in which the generation (or source) is located. The "Sink Balancing Authority" is the Balancing Authority in which the load (or sink) is located. If there is another Balancing Authority on the scheduling path of an Interchange Transaction, it is known as an "Intermediate Balancing Authority."

For Dynamic Transfers,[11] NERC proposes to define the terms "Attaining Balancing Authority" and "Native Balancing Authority." The Attaining Balancing Authority is the "Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority." The Native Balancing Authority is the "Balancing Authority from which a portion of its physically interconnected generation and/or

[11] A "Dynamic Transfer" is defined in the NERC Glossary as the "provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another."

load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer."

The Interchange Authority is the responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.

2. Mechanics of an Interchange Transaction

An Interchange Schedule is the method by which the Source and Sink Balancing Authorities agree upon the Interchange Transaction size (measured in megawatts), the start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of the power and energy. Net Scheduled Interchange is the algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time. An Interchange Transaction Tag or Tag is an electronic tag that contains all of the transaction information and is used to populate the Interchange Distribution Calculator which identifies transactions that are impacting Flowgates.[12] Communication, submission, assessment and approval of a Tag must be completed for reliability consideration before implementation of the transaction. The Distribution Factor is the portion of an Interchange Transaction that flows across a transmission facility (Flowgate).

Arranged Interchange is the state where a Request for Interchange (initial or revised) has been submitted for approval. Confirmed Interchange is the state where no party has denied and all required parties have approved the Arranged Interchange. Implemented Interchange is the state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error

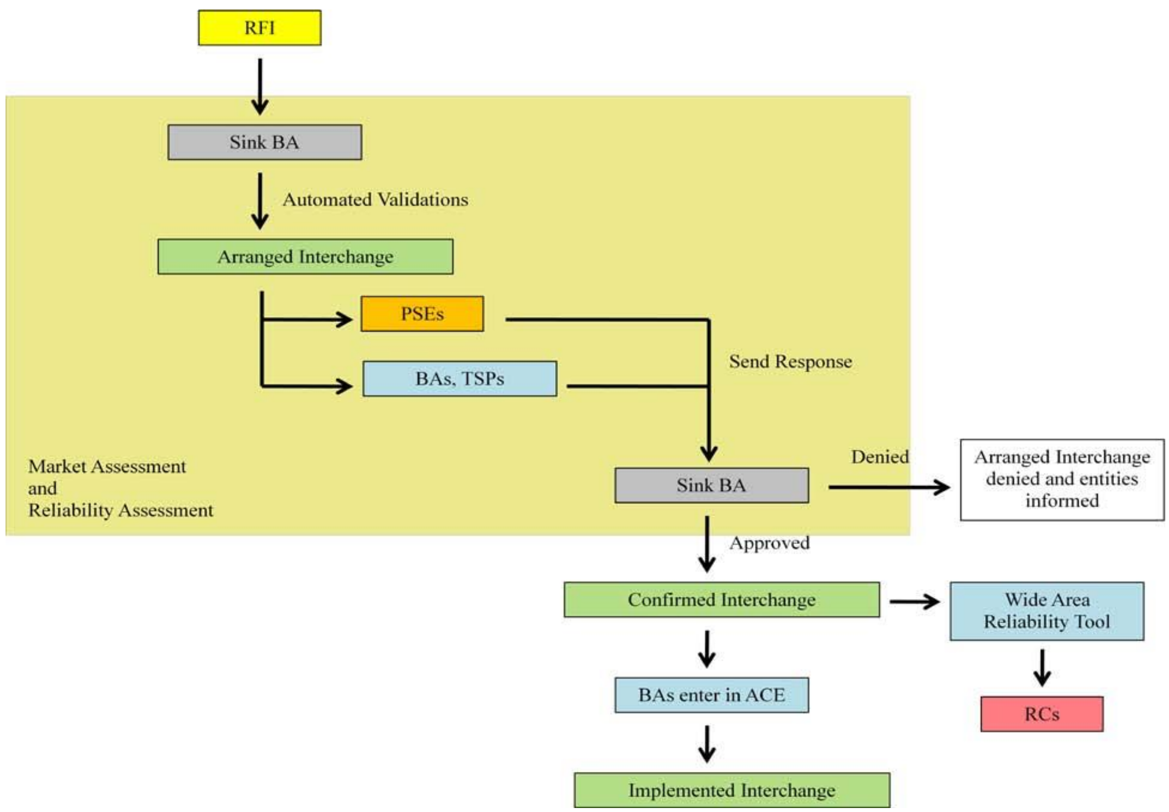
[12] A "Flowgate" is defined in the NERC Glossary as: "1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System."

equation.[13] The proposed definition of "Composite Confirmed Interchange" is "[t]he energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period."

Net Actual Interchange is the algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas. Inadvertent Interchange is the difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange.

The proposed definition of "Reliability Adjustment Arranged Interchange" is a request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

Provided below is Figure **A**, which depicts the typical reliability-related steps in coordinating Interchange and is provided for informational purposes.



13 Area Control Error or "ACE" is the instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.

The North American Energy Standards Board ("NAESB") has several Coordinate Interchange Business Practice Standards that establish the Interchange Transaction requirements for coordination of commercial arrangements and that complement the NERC Reliability Standards.

3. Dynamic Interchange Schedules and Pseudo-Ties

A Dynamic Schedule is implemented as an Interchange Transaction that is modified in real-time to transfer time-varying amounts of power between Balancing Authorities. Dynamic Schedules are commonly used for scheduling jointly-owned generation to or from another Balancing Authority Area. The proposed revisions to the term "Dynamic Interchange Schedule or Dynamic Schedule" clarify that a Dynamic Schedule is updated in Real-time and is included in the Scheduled Net Interchange term in the affected Balancing Authorities' control ACE equations (or alternative control processes).

Pseudo-Ties are often employed to assign generators, loads, or both from the Balancing Authority to which they are physically connected into a Balancing Authority that has effective operational control of them. Thus, Pseudo-Ties often provide for change of Balancing Authority operational responsibility from the native to the Attaining Balancing Authority and at the same time make the Attaining Balancing Authority provider of Balancing Authority services. In practice, Pseudo-Ties may be implemented based upon metered or calculated values. All Balancing Authorities involved account for the power exchange and associated transmission losses as actual interchange between the Balancing Authorities, both in their ACE equations and throughout all of their energy accounting processes.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[14]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[15] Congress entrusted the Commission 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 ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[16] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[17] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability

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14 Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.
15 16 U.S.C. § 824o (2006).
16 *Id.* § 824(b)(1).
17 *Id.* § 824o(d)(5).

Standard. Section 39.5(a)[18] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[19] and Section 39.5(c)[20] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[21] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[22] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable

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18 18 C.F.R. § 39.5(a) (2012).

19 16 U.S.C. § 824o(d)(2).

20 18 C.F.R. § 39.5(c)(1).

21 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.").

22 The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

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. 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 before the Reliability Standard is submitted to the Commission for approval.

IV. JUSTIFICATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS

As discussed in detail in **Exhibit C**, the proposed Reliability Standards satisfy the Commission's criteria in Order No. 672 and are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Provided below is the following: (1) a description of each proposed Reliability Standard and discussion of how applicable Commission directives are satisfied; and (2) justification for the proposed Reliability Standards on a Requirement-by-Requirement basis.

A. Proposed Reliability Standard INT-004-3– Dynamic Transfers

The purpose of proposed Reliability Standard INT-004-3 is to ensure that Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.

1. Procedural History

Reliability Standard INT-004-1, was approved by the Commission in Order No. 693.[23] Reliability Standard INT-004-2 was accepted by the Commission in Order No. 713.[24]

2. Requirement-by-Requirement Justification

Proposed Reliability Standard INT-004-3 consists of three Requirements and is applicable to Balancing Authorities and Purchasing-Selling Entities.[25] Provided below is an explanation of each of the Requirements of proposed Reliability Standard INT-004-3.

INT-004-3, Requirement R1

R1 Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1] Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method.

[FN 1 Please refer to the timing tables of INT-006-4.]

Proposed Requirement R1 is intended to ensure that a Request for Interchange is submitted for a Dynamic Schedule or for a Pseudo-Tie that is not otherwise considered in congestion management procedure(s). If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount. This requirement was formerly included in Reliability Standard INT-001-3, which is proposed for retirement. The proposed revisions to Requirement R1 now include Pseudo-Ties.

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[23] *Mandatory Reliability Standards for the Bulk-Power System*, Order 693, 118 FERC ¶ 61,218 at P 843 (2007).

[24] *Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, Order No. 713, 124 FERC ¶ 61,071 at P 57 (2008).

[25] The Standard Drafting Team considered the remarks of Santa Clara in determining the appropriate applicability of the INT Reliability Standards, in compliance with Order No. 693 at P 819.

The requirement to create a Request for Interchange for Pseudo-Ties ensures that all entities involved are aware of the Dynamic Transfer and that the various responsibilities associated with the Dynamic Transfer have been agreed upon.

INT-004-3, Requirement R2

R2. The Purchasing-Selling Entity that submits a Request for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:**

- **2.1.** For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.
- **2.2.** For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.
- **2.3.** The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

Proposed Requirement R2 specifies conditions under which the Confirmed Interchange is updated in order to support congestion management procedures. The elements of this requirement were formerly included in Reliability Standard INT-004-2, Requirement R2 and like proposed Requirement R1, Requirement R2 has been revised to include Pseudo-Ties.

INT-004-3, Requirement R3

R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures.

Proposed Requirement R3 applies to Balancing Authorities and was created to ensure that coordination occurs between all entities involved, prior to the initial implementation of a Pseudo-Tie. The NAESB Electric Industry Registry is where all of the interfaces for Interchange are defined. A request to revise the NAESB Electric Industry Registry has already been submitted for implementation.[26]

B. Proposed Reliability Standard INT-006-4 – Evaluation of Interchange Transactions

The purpose of proposed Reliability Standard INT-006-4 is to ensure that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented.

1. Procedural History

Reliability Standard INT-006-1 was accepted by the Commission in Order No. 693.[27] INT-006-2 was accepted by the Commission in Order No. 713.[28] Reliability Standard INT-006-3 was accepted by the Commission in Order No. 730.[29]

2. Requirement-by-Requirement Justification

Proposed Reliability Standard INT-006-4 consists of five Requirements and is applicable to Balancing Authorities and Transmission Service Providers. Attachment 1 provides timing requirements for each of the Interconnections and is incorporated into each of the Requirements of INT-006-4. Provided below is an explanation of each of the Requirements of proposed Reliability Standard INT-006-4.

INT-006-4, Requirement R1

R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B.

1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting

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26 This requirement is proposed to become effective on the first calendar day two calendar quarters after the NAESB Electric Industry Registry is able to accept Pseudo-Tie registrations. All existing and future Pseudo-Ties are to be registered in the NAESB Electric Industry Registry.

27 Order No. 693 at P 859.

28 Order No. 713 at P 67.

29 *Revised Mandatory Reliability Standards for Interchange Scheduling and Coordination*, Order No. 730, 129 FERC ¶ 61,223 at P 13 (2009).

the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

Proposed Requirement R1 requires Balancing Authorities to take action on a received Arranged Interchange within a certain timeframe, which is specified in Attachment 1. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny for other reasons, such as economic or contractual issues, as outlined in the NAESB Business Practices. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation. Proposed Requirement R1 is based on Requirement R1 of the currently-effective Reliability Standard INT-006-3.

INT-006-4, Requirement R2

R2. Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B.

2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

Transmission Service Providers must take action on a received Arranged Interchange within a certain timeframe, which is specified in Attachment 1. Requirement R2, Part 2.1 provides reliability-related reasons that a Transmission Service Provider must deny an Arranged Interchange, but Transmission Service Providers may deny for other reasons. If the conditions described in Requirement R2, Part 2.1 are recognized after approval is granted, the Transmission

Service Provider may curtail the Confirmed Interchange prior to implementation. Proposed Requirement R2 is based on Requirement R1 of the currently-effective Reliability Standard INT-006-3.

INT-006-4, Requirement R3

R3. The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.

> **3.1.** If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.

Proposed Requirement R3 ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange. Proposed Requirement R3 is based on Requirement R1 of the currently-effective Reliability Standard INT-006-3.

INT-006-4, Requirement R4

R4. Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange:

- It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

Proposed Requirement R4 lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange. This is designed to ensure that there is appropriate verification of information prior to the transition from Arranged Interchange to Confirmed Interchange. Proposed Requirement R4 is based on Requirement R1 of currently-effective Reliability Standard INT-007-1, which is proposed for retirement.

INT-006-4, Requirement R5

R5. For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D:

- **5.1.** The Source Balancing Authority,
- **5.2.** Each Intermediate Balancing Authority,
- **5.3.** Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,
- **5.4.** Each Transmission Service Provider included in the Arranged Interchange, and
- **5.5.** Each Purchasing Selling Entity included in the Arranged Interchange.

This requirement lists the entities to which a Sink Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange. Proposed Requirement R5 is based on Requirement R1 of currently-effective Reliability Standard INT-008-3 (proposed for retirement herein).[30]

C. Proposed Reliability Standard INT-009-2– Implementation of Interchange

The purpose of proposed Reliability Standard INT-009-2 is to ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.

1. Procedural History

Reliability Standard INT-009-1 was accepted by the Commission in Order No. 693.[31]

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[30] *Infra*. at 27-28.

[31] Order No. 693 at P 875.

2. Requirement-by-Requirement Justification

Proposed Reliability Standard INT-009-2 consists of three Requirements and is applicable to Balancing Authorities. Provided below is an explanation of each of the Requirements of proposed Reliability Standard INT-009-2.

INT-009-2, Requirement R1

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is:

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and
1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

This proposed Requirement has been revised to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities. Proposed Requirement R1 is based on Requirement R1 of currently-effective Reliability Standard INT-003-3 (proposed for retirement herein).[32]

INT-009-2, Requirement R2

R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process).

Proposed Requirement R2 is a new Requirement that is intended to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Actual Net Interchange term for their ACE controls. Requirement R12.3 of currently-effective Reliability Standard BAL-005-0.2b addresses common metering for Dynamic Schedules and Pseudo-Ties

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32 *Infra.* at 23-24.

but not their implementation into ACE. Requirement R2 is parallel to R10 of BAL-005-0.2b, which only addresses Dynamic Schedules, although this proposed Requirement applies to Pseudo-Ties.

INT-009-2, Requirement R3

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

This proposed Requirement ensures that the Balancing Authority that controls a high-voltage direct current tie coordinates the Confirmed Interchange. Proposed Requirement R3 is based on Requirement R1.2 from currently-effective Reliability Standard INT-003-3 (proposed for retirement herein).[33]

By incorporating Requirements from currently-effective Reliability Standard INT-003-3, the proposed Reliability Standard INT-009-2 is intended to ensure that Balancing Authorities confirm Interchange Schedules and implement the Interchange as agreed upon in the Interchange confirmation process.

D. Proposed Reliability Standard INT-010-2 – Interchange Initiation and Modification for Reliability

The purpose of proposed Reliability Standard INT-010-2 is to provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.

1. <u>Procedural History</u>

Reliability Standard INT-010-1 was accepted by the Commission in Order No. 693.[34]

[33] *Supra* at 24-25.
[34] Order No. 693 at P 887.

2. Requirement-by-Requirement Justification

Proposed Reliability Standard INT-010-2 consists of three Requirements and is applicable to Balancing Authorities. Provided below is an explanation of each of the Requirements of proposed Reliability Standard INT-010-2.

INT-010-2, Requirement R1

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required.

Proposed Requirement R1 has been modified to replace the term "request for Arranged Interchange" with the corrected term "Request for Interchange," which is a defined term in the NERC Glossary. Revisions to the definition of "Request for Interchange" are also proposed herein.[35]

INT-010-2, Requirement R2

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons.

Proposed Requirement R2 has been revised to apply to "Sink Balancing Authorities" instead of "Reliability Coordinators" to provide clarity as to which entity is to perform the reliability task. The revised language clarifies that the Sink Balancing Authority is the responsible entity.

35 *Supra* at 33.

INT-010-2, Requirement R3

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons.

Proposed Requirement R3 has been revised to apply to "Sink Balancing Authorities" instead of "Reliability Coordinators" to provide clarity as to which entity is to perform the reliability task. The revised language clarifies that the Sink Balancing Authority is the responsible entity.

E. Proposed Reliability Standard INT-011-1 – Intra-Balancing Authority Transaction Identification

Proposed Reliability Standard INT-011-1 is a new Reliability Standard, and the purpose of the Standard is to ensure that transfers within a Balancing Authority Area using Point-to-Point Transmission Service are communicated and accounted for in congestion management procedures.

1. Requirement-by-Requirement Justification

Proposed Reliability Standard INT-011-1 consists of one Requirement and is applicable to Load-Serving Entities. Provided below is the full text and a subsequent explanation of Requirement R1.

INT-011-1, Requirement R1

R1. Each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange unless the information about intra-Balancing Authority transfers is included in congestion management procedure(s) via an alternate method.

Proposed Requirement R1 of INT-011-1 addresses the Commission's directive in Paragraph 817 of Order No. 693. The Commission "direct[ed] the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and 'non-Order No. 888' transfers."[36] While Reliability Standard INT-001-3 is proposed for retirement, the Commission's directive is addressed via proposed Reliability Standard INT-011-1.

The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and proposed Reliability Standard INT-011-1 ensures that these transfers are communicated and accounted for in congestion management procedures. If a transfer within a Balancing Authority Area is submitted as a Request for Interchange or otherwise accounted for in congestion management procedures, it can be evaluated and processed comparable to a Request for Interchange that crosses Balancing Authority Areas.

V. JUSTIFICATION FOR PROPOSED RETIREMENT OF RELIABILITY STANDARDS

NERC proposes to retire the following five currently-effective Reliability Standards: INT-001-3– Interchange Information; INT-003-3 – Interchange Transaction Implementation; INT-005-3 – Interchange Authority Distributes Arranged Interchange; INT-007-1– Interchange Confirmation; and INT-008-3—Interchange Authority Distributes Status. Provided below is the following: (1) a description of each proposed Reliability Standard, including the procedural history; and (2) justification for the proposed retirement.

[36] Order No. 693 at P 817.

A. Proposed Retirement of Reliability Standard INT-001-3 – Interchange Information

The purpose of Reliability Standard INT-001-3 is to "ensure that Interchange Information is submitted to the NERC-identified reliability analysis service."

1. Procedural History

Reliability Standard INT-001-2, which superseded the Version 1 Reliability Standard INT-001-1, was approved by the Commission in Order No. 693.[37] Reliability Standard INT-001-3 was approved by the Commission in Order No. 713.[38]

2. Retirement Justification

Reliability Standard INT-001-3 consists of two Requirements and applies to Purchasing-Selling Entities and Balancing Authorities. Requirement R1 has been revised and incorporated into proposed Reliability Standard INT-004-3– Dynamic Transfers, as explained herein.[39] Requirement R2 of INT-001-3 is proposed for retirement, and this retirement can be removed with little or no effect on reliability, consistent with Commission precedent, because the proposed Requirement R1 of Reliability Standard INT-009-2 makes it clear that the Net Scheduled Interchange term in the control equation can only include Confirmed Interchange as agreed to between Balancing Authorities. This, by definition, requires that an Arranged Interchange be created in order to implement the schedules listed in Requirements R2.1 and R2.2.

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37 Order No. 693 at P 814.

38 Order No. 713 at P 57.

39 *Supra* at 12.

B. Proposed Retirement of Reliability Standard INT-003-3 – Interchange Transaction Implementation

The purpose of Reliability Standard INT-003-3 is to ensure that Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their ACE equations.

1. Procedural History

In approving INT-003-1, the Commission proposed to direct NERC to submit a modification to INT-003-1 that includes Measures and Levels of Non-Compliance. NERC filed INT-003-2 with the Commission on November 15, 2006 to replace the Version 1 Reliability Standard INT-003-1 and add Measures and Levels of Non-Compliance pursuant to Commission directives. INT-003-2 was approved by the Commission on March 16, 2007 in Order No. 693.[40] On November 20, 2009, NERC submitted a proposal for the Commission to approve Reliability Standard INT-003-3, which would supersede INT-003-2 and remove the MISO tagging waivers that were once necessary to accommodate the operation of the MISO market in a multi-Balancing Authority environment.[41] Because MISO is now a single Balancing Authority for the geographic region it encompasses, NERC determined this waiver was not needed. Reliability Standard INT-003-3 was approved by the Commission on January 6, 2011.[42]

2. Retirement Justification

Reliability Standard INT-003-3 consists of one Requirement and is applicable to Balancing Authorities. While this Reliability Standard is proposed for retirement, Requirement R1 has been incorporated into Requirement R1 of the proposed Reliability Standard, INT-009-

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[40] Order No. 693 at P 833.

[41] *Petition of the North American Electric Reliability Corporation for Approval of Two Reliability Standards Revisions to Withdraw MISO Waivers*, Docket No. RD10-4 (November 20, 2009).

[42] *North American Electric Reliability Corp*., 134 FERC ¶ 61,007 at P 6 (2011).

2.[43] The purpose of INT-003-3, to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities, is maintained in proposed Reliability Standard INT-009-2. As explained herein, Requirement R3 of proposed Reliability Standard INT-009-2 is based on Requirement R1.2 of INT-003-3 and ensures that Confirmed Interchange on a high-voltage direct current tie is coordinated with the Transmission Operators.[44]

C. Proposed Retirement of Reliability Standard INT-005-3 – Interchange Authority Distributes Arranged Interchange

The purpose of Reliability Standard INT-005-3 is to ensure that the implementation of Interchange between Source and Sink Balancing Authorities is distributed by an Interchange Authority such that Interchange information is available for reliability assessments.

1. <u>Procedural History</u>

Reliability Standard INT-005-1 was accepted by the Commission in Order No. 693, wherein the Commission directed NERC to consider adding additional Measures and Levels of Non-Compliance to the Reliability Standard.[45] Reliability Standard INT-005-2, which superseded the Version 1 Reliability Standard INT-005-1, was one of several standards that aimed to increase the timeframe for applicable WECC entities to perform the reliability assessment from five to ten minutes for next hour interchange tags submitted in the first thirty minutes of the hour before. INT-005-2 was approved by the Commission in Order No. 713.[46] Reliability Standard INT-005-3 was approved by the Commission in Order No. 730 to help facilitate the reliable operation of the Bulk-Power System by providing WECC entities sufficient

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[43] *Supra* at 18.
[44] *Supra* at 19.
[45] Order No. 693 at P 847, 848
[46] Order No. 713 at P 67.

time to assess and response to requests for interchange service before the underlying e-Tags for these requests expire, and by clarifying timing requirements for all affected entities.[47]

2. Retirement Justification

Currently-effective Reliability Standard INT-005-3 consists of one Requirement and is applicable to Interchange Authorities. The *Electronic Tagging Functional Specification*, which is a NAESB document, describes the functional requirements and detailed technical specifications for the implementation of an electronic tag or e-Tag. Section 3.6.1.1.1 of this document requires the identification of a distribution list for an e-Tag. Accordingly, the task set forth in Requirement R1 of INT-005-3 is not necessary and the proposed retirement of this Reliability Standard will not create a reliability gap.

D. Proposed Retirement of Reliability Standard INT-007-1– Interchange Confirmation

The purpose of Reliability Standard INT-007-1 is to ensure that Arranged Interchange is checked for reliability before it is implemented. Reliability Standard INT-007 requires that before changing the status of submitted Arranged Interchange to Confirmed Interchange, the Interchange Authority must verify that the submitted Arranged Interchange is valid and complete with relevant information and approvals from the Balancing Authorities and transmission service providers.

1. Procedural History

Reliability Standard INT-007-1 was submitted for Commission approval on August 28, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.[48] On February 28, 2013, NERC filed a petition with the Commission requesting retirement of

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47 Order No. 730 at P 13-14.

48 Order No. 693 at P 867.

Requirement R1.2 of INT-007-1 due to the fact that this requirement was considered an outdated administrative task after the implementation of the NAESB Electric Industry Registry. The Commission approved the retirement of this Requirement in Order No. 788.[49]

2. Retirement Justification

Currently-effective Reliability Standard INT-007-1 consists of one Requirement and applies to Interchange Authorities. The reliability purpose of INT-007-1 is to ensure that each Arranged Interchange is checked for reliability before it is implemented, and this purpose is unaffected by the proposed retirement, as proposed Reliability Standard INT-006-4 is designed to ensure that this action occurs. Specifically, proposed Requirement R4 of INT-006-4 specifies conditions under which the Sink Balancing Authority shall not transition to Confirmed Interchange. Requirement R1.4 of currently-effective Reliability Standard INT-007-1 is also addressed via the proposed revisions to the definition of the term "Confirmed Interchange," which clarify that this is a "state where no party has denied and all required parties have approved the Arranged Interchange." For these reasons, the proposed retirement of Reliability Standard INT-007-1 presents no reliability gap.

E. Proposed Retirement of Reliability Standard INT-008-3—Interchange Authority Distributes Status

The purpose of Reliability Standard INT-008-3 is to ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority.

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49 *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61, 147 at P 17 (2013).

1. Procedural History

Reliability Standard INT-008-1 was submitted for Commission approval on August 28, 2006 and approved in Order No. 693, pending further clarification on a permanent entity to serve as interchange authority.[50] Reliability Standard INT-008-2, which superseded the Version 1 Reliability Standard INT-008-1, was proposed by the NERC Standards Committee through the urgent action process in February 2007 as part of an effort to increase an aspect of the timing table commonly contained in each reliability standard.[51] The Commission approved INT-008-2 in Order No. 713.[52] Finally, Reliability Standard INT-008-3, which superseded the Version 2 Reliability Standard INT-008-2, was submitted to the Commission on February 5, 2009 and included a variety of insubstantial changes to the timing tables in addition to those included in the original urgent action process.[53] The Commission approved INT-008-3 in Order No. 730 on December 17, 2009.[54]

2. Retirement Justification

Currently-effective Reliability Standard INT-008-3 consists of one Requirement and is applicable to Interchange Authorities. The reliability purpose of INT-008-3 is unaffected by this proposed retirement as Requirement R5 of proposed Reliability Standard INT-006-4 lists the entities to which a Sink Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.[55] For this reason, the proposed retirement of Reliability Standard INT-008-3 presents no reliability gap.

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50 Order No. 693 at P 872.

51 *Petition Of The North American Electric Reliability Corporation For Approval Of Five (5) Proposed Reliability Standards*, Docket No. RM08-7 (December 26, 2007).

52 Order No. 713 at P 67.

53 *Petition of the North American Electric Reliability Corporation for Approval Of INT-005-3, INT-006-3 and INT-008-3 Reliability Standards and Three Associated Terms*, Docket No. RM09-8 (February 5, 2009).

54 Order No. 730 at P 13.

55 *Supra* at 17.

VI. JUSTIFICATION FOR PROPOSED DEFINITIONS

NERC proposes revisions to ten definitions in the NERC Glossary of Terms (Adjacent Balancing Authority; Arranged Interchange; Confirmed Interchange; Dynamic Interchange Schedule or Dynamic Schedule; Intermediate Balancing Authority; Operational Planning Analysis; Pseudo-Tie; Request for Interchange; Sink Balancing Authority; and Source Balancing Authority) and four new definitions (Attaining Balancing Authority; Composite Confirmed Interchange; Native Balancing Authority; and Reliability Adjustment Arranged Interchange) for Commission approval. Provided below is the full text of each proposed definition and an explanation of the proposed revisions.

A. Proposed Revised Definition of "Adjacent Balancing Authority"

NERC proposes the following revised definition of the term "Adjacent Balancing Authority:"

Adjacent Balancing Authority - A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

The proposed revisions are minor, non-substantive changes to improve the clarity of the term, as illustrated in **Exhibit F**. The proposed revisions are intended to clarify the various Balancing Authorities involved in the implementation of Interchange and their relationships with regards to Interchange.

B. Proposed Revised Definition of "Arranged Interchange"

NERC proposes the following revised definition of the term "Arranged Interchange:"

Arranged Interchange - The state where a Request for Interchange (initial or revised) has been submitted for approval.

The proposed revisions to the term "Arranged Interchange" remove references to the "Interchange Authority," to provide clarity. This proposed term is now based solely on NAESB

Business Practice Standards and definitions rather than any entity that may be responsible for its application for reliability.

C. Proposed Revised Definition of "Confirmed Interchange"

NERC proposes the following revised definition of the term "Confirmed Interchange:"

Confirmed Interchange - The state where no party has denied and all required parties have approved the Arranged Interchange.

The proposed revisions to the term "Confirmed Interchange" are necessary to clarify the various stages of Interchange and are designed to ensure that Arranged Interchange is checked for reliability purposes before it is implemented.

D. Proposed Revised Definition of "Dynamic Interchange Schedule or Dynamic Schedule"

NERC proposes the following revised definition of the term "Dynamic Interchange Schedule or Dynamic Schedule:"

Dynamic Interchange Schedule or Dynamic Schedule: A time-varying energy transfer that is updated in Real-time and included in the Scheduled Net Interchange term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).

This defined term was revised to provide clarity that a Dynamic Schedule is updated in Real-time and is included in the Scheduled Net Interchange term in the affected Balancing Authorities' control ACE equations (or alternate control processes). Dynamic Schedules are commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.

E. Proposed Revised Definition of "Intermediate Balancing Authority"

NERC proposes the following revised definition of the term "Intermediate Balancing Authority:"

Intermediate Balancing Authority - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.

The proposed revisions to "Intermediate Balancing Authority" are intended to clarify the various Balancing Authorities involved in the implementation of Interchange and their relationships with regards to Interchange.

F. Proposed Revised Definition of "Operational Planning Analysis"

NERC proposes the following revised definition of the term "Operational Planning Analysis:"

Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

The proposed revisions to the term "Operational Planning Analysis" are presented as an equally effective and efficient alternative to addressing the Commission's concerns regarding Reliability Standard INT-006-1 in Order No. 693. The Commission directed:

> the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation.[56]

The term "Operational Planning Analysis" is used in Reliability Standards that apply to both Reliability Coordinators and Transmission Operators. Currently-effective Reliability Standard IRO-008-1 applies to Reliability Coordinators and Requirement R1 requires each

[56] Order No. 693 at P 866.

Reliability Coordinator to perform an Operational Planning Analysis.[57] By explicitly including "Interchange" in the definition of "Operational Planning Analysis," the Reliability Coordinator must consider Interchange when performing the analysis required in Reliability Standard IRO-008-1. This addresses the Commission's concern in Order No. 693 regarding the need for Reliability Coordinators to review energy Interchange Transactions from a wide-area perspective for potential detrimental reliability impacts. When the results of the analysis indicate the need for action, Requirement R3 of Reliability Standard IRO-008-1 requires the Reliability Coordinator to share its results with those entities that are expected to take those actions.[58] The proposed modified to "Operational Planning Analysis" is intended to ensure that Transmission Operators would be able to review Interchange Transactions from a local area reliability perspective.

G. Proposed Revised Definition of "Pseudo-Tie"

NERC proposes the following revised definition of the term "Pseudo-Tie:"

Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NI_A) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

The proposed revisions to this defined term are intended to clarify that a Pseudo-Tie is updated in Real-time and is included in the Actual Net Interchange (NI_A) term in the affected Balancing Authorities' control ACE equations (or alternate control processes). Pseudo-Ties are

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57 IRO-008-1, Requirement R1 provides: R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions.

58 IRO-008-1, Requirement R3 provides: R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.

commonly used as a "virtual" tie line flow in the ACE equation but for which no physical tie or energy metering actually exists.

H. Proposed Revised Definition of "Request for Interchange"

NERC proposes the following revised definition of the term "Request for Interchange:"

Request for Interchange - A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.

The proposed revisions to "Request for Interchange" are intended to eliminate ambiguity by removing references to the Interchange Authority. The proposed revisions are also consistent with NAESB Business Practice Standards. This defined term is also contained within the term "Emergency Request for Interchange" and the proposed revisions are consistent with that intended meaning.

I. Proposed Revised Definition of "Sink Balancing Authority"

NERC proposes the following revised definition of the term "Sink Balancing Authority:"

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.

The proposed revisions to "Sink Balancing Authority" are intended to clarify the various Balancing Authorities involved in the implementation of Interchange and their relationships with regards to Interchange.

J. Proposed Revised Definition of "Source Balancing Authority"

NERC proposes the following revised definition of the term "Source Balancing Authority:"

Source Balancing Authority - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.

The proposed revisions to "Source Balancing Authority" are intended to clarify the various Balancing Authorities involved in the implementation of Interchange and their relationships with regards to Interchange.

K. Proposed Newly Defined Term "Attaining Balancing Authority"

NERC proposes the following new definition for the term "Attaining Balancing Authority:"

Attaining Balancing Authority: A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.

The proposed term "Attaining Balancing Authority" is intended to clarify the various Balancing Authorities involved in the implementation of Interchange and their relationships with regards to Interchange. The term "Attaining Balancing Authority" is also used in the NERC Operating Manual.[59]

L. Proposed Newly Defined Term "Composite Confirmed Interchange"

NERC proposes the following new definition for the term "Composite Confirmed Interchange:"

Composite Confirmed Interchange – The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.

The proposed term "Composite Confirmed Interchange" was developed to define what is included in proposed Reliability Standard INT-009-2, Requirement R1 to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.

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59 *Available at*: http://www.nerc.com/files/opman_3_2012.pdf.

M. Proposed Newly Defined Term "Native Balancing Authority"

NERC proposes the following new definition for the term "Native Balancing Authority:"

Native Balancing Authority: A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

The proposed term "Native Balancing Authority" is intended to clarify the various Balancing Authorities involved in the implementation of Interchange and their relationships with regards to Interchange. The term "Native Balancing Authority" is also used in the NERC Operating Manual.[60]

N. Proposed Newly Defined Term "Reliability Adjustment Arranged Interchange"

NERC proposes the following new definition for the term "Reliability Adjustment Arranged Interchange:"

Reliability Adjustment Arranged Interchange – A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

The proposed term "Reliability Adjustment Arrange Interchange" was developed to accurately reflect the types of Interchange that are adjusted for reliability reasons.

O. Enforceability of the Proposed Reliability Standards

The proposed Reliability Standards include Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"). The VSLs provide guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standards. The VRFs are one of several elements used to determine an appropriate sanction when the associated Requirement is violated. The VRFs assess the impact to reliability of violating a specific Requirement. The VRFs and

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60 *Available at*: http://www.nerc.com/files/opman_3_2012.pdf.

VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. For a detailed review of the VRFs, the VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines, please see **Exhibit G**.

The proposed Reliability Standards also include Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. These Measures help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[61]

[61] Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

VII. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission:

- approve the proposed Reliability Standards, definitions, and associated elements included in **Exhibit A,** effective as proposed herein;
- approve the implementation plan included in **Exhibit B**; and
- approve the retirement of Reliability Standards, effective as proposed herein.

Respectfully submitted,

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Date: February 27, 2014

Exhibit A

Proposed Reliability Standards and Definitions

A. Introduction

1. **Title:** **Dynamic Transfers**
2. **Number:** INT-004-3
3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Purchasing-Selling Entity
5. **Effective Date:**

   First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of Dynamic Transfers.

   - R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement now includes Pseudo-Ties.
   - R2 is modified from INT-004-2 to separate the triggers for the review of the Dynamic Transfer and when a modification is required for the Dynamic Transfer.
   - R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo-Ties ensure that all entities involved are aware of the Dynamic Transfer and agree that the various responsibilities associated with the dynamic transfer have been agreed upon.
   - R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
   - The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any Dynamic Transfer.

B. Requirements and Measures

R1. Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1] Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]

M1. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-Tie. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the Purchasing-Selling Entity shall have evidence such as Interchange Distribution Calculator model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)

R2. The Purchasing-Selling Entity that submits a Request for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.

2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.

2.3. The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

M2. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation met the criteria in Requirement R2, Parts 2.1- 2.3. (R2)

R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support

[1] Please refer to the timing tables of INT-006-4.

congestion management procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Purchasing-Selling Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Purchasing-Selling Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a Purchasing-Selling Entity or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.

R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-Ties are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as Scheduled Interchange. The obligations of the entities involved in each type of Dynamic Transfer are dependent on the type of Dynamic Transfer selected. These guidelines provide items that should be considered when determining which type of Dynamic Transfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a Dynamic Transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
    - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services FERC OATT Schedules 3–6 and other ancillary services	Attaining BA	Native BA

as required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE Frequency Bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their Frequency Bias Setting to account for the Frequency Bias characteristics of the loads and/or resources being assigned between BA(s) by the Pseudo-Tie	The Attaining BA should include the Load from its Dynamic Schedule as a part of its forecast load to set Frequency Bias requirement. The Native BA should change its Load used to set Frequency Bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

The unique handling of curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale R1:

This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

Rationale R2:

This requirement does not preclude tags from being updated at any time. The requirement specifies conditions under which the tag must be updated.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	February 6, 2014	Adopted by the NERC Board of Trustees	Revised

A. Introduction

1. **Title:** **Dynamic ~~Interchange Transaction Modifications~~Transfers**

2. **Number:** INT-004-~~2~~3

3. **Purpose:**~~-~~ To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Purchasing-Selling Entity

5. **Effective Date:**~~Transfers are adequately tagged to be able~~

   First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   ~~3.~~ This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ~~determine their reliability impacts.~~ensure the transparency of Dynamic Transfers.

~~4. **Applicability**~~

~~4.1. Balancing Authorities~~

~~4.2. Reliability Coordinators~~

~~4.3. Transmission Operators~~

~~4.4. Purchasing-Selling Entities~~

- R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement now includes Pseudo-Ties.
- R2 is modified from INT-004-2 to separate the triggers for the review of the Dynamic Transfer and when a modification is required for the Dynamic Transfer.
- R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo-Ties ensure that all entities involved are aware of the Dynamic Transfer and agree that the various responsibilities associated with the dynamic transfer have been agreed upon.
- R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.

- The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any Dynamic Transfer.

~~5. Effective Date: August 27, 2008 (U.S.)~~

~~NERC Board Approval: October 9, 2007~~

B. Requirements and Measures

~~**R2.** At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.~~

R1. ~~The~~ Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1] Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]

M1. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-Tie. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the Purchasing-Selling Entity shall have evidence such as Interchange Distribution Calculator model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)

R2. The Purchasing-Selling Entity that submits a Request for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

~~**R3.**~~ For Confirmed Interchange ~~Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs:~~

~~R2.1.~~2.1. ~~The average energy profile in an hour is~~ greater than 250 MW ~~and in that~~for the last hour, the actual hourly integrated energy deviates from the ~~hourly average energy profile indicated on the tag~~Confirmed Interchange by more than ~~±10%.~~10% for that hour and that deviation is expected to persist.

[1] Please refer to the timing tables of INT-006-4.

~~R2.2.~~2.2. ~~The average energy profile in an hour is~~ For Confirmed Interchange less than or equal to 250 MW ~~and in that~~for the last hour, the actual hourly integrated energy deviates from the ~~hourly average energy profile indicated on the tag~~Confirmed Interchange by more than ~~+25 megawatt-hours~~25 MW for that hour and that deviation is expected to persist.

~~R2.3.~~2.3. ~~A~~The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator ~~determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.~~to update the Confirmed Interchange.

~~**C. Measures**~~

~~M1.~~M2. The ~~Sink Balancing Authority shall provide evidence that the responsible~~ Purchasing-Selling Entity ~~revised a tag~~shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation ~~exceeded~~met the criteria in ~~INT-004~~ Requirement R2, Parts 2.1- 2.3. (R2)

R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. (R3)

~~D.~~C. Compliance

1. Compliance Monitoring Process

~~Periodic tag audit~~

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Purchasing-Selling Entity shall keep data or evidence to show compliance as ~~prescribed~~identified below unless directed by ~~NERC. For the requested time~~ its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period~~, the Sink~~ of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Purchasing-Selling Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.

- The Balancing Authority shall ~~provide the instances when Dynamic Schedule deviation exceeded the criteria in INT-004 R2 and shall provide~~maintain evidence ~~that the responsible~~to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a Purchasing-Selling Entity or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

~~1.~~ The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted ~~a revised tag.~~subsequent audit records.

~~1.1.~~1.3. Compliance Monitoring ~~Responsibility~~and Assessment Processes:

~~Regional Reliability Organization.~~

~~1.2.~~ Compliance **~~Monitoring Period and Reset Time Frame~~**Audit

~~One calendar year without a violation from the time of the violation.~~

~~1.3. Data Retention~~

~~Three months.~~

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

~~Not specified.~~

~~2.~~ **~~Levels~~**None

~~3.~~ Table of ~~Non-~~Compliance Elements

~~3.1. Level 1: Not specified.~~

~~3.2. Level 2: Not specified.~~

~~3.3. Level 3: Not specified.~~

~~3.4. Level 4: Not specified.~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that

						the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.
R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.

~~E.~~D. Regional ~~Differences~~Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-Ties are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as Scheduled Interchange. The obligations of the entities involved in each type of Dynamic Transfer are dependent on the type of Dynamic Transfer selected. These guidelines provide items that should be considered when determining which type of Dynamic Transfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a Dynamic Transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
    - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services	Attaining BA	Native BA

FERC OATT Schedules 3–6 and other ancillary services as required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE Frequency Bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their Frequency Bias Setting to account for the Frequency Bias characteristics of the loads and/or resources being assigned between BA(s) by the Pseudo-Tie	The Attaining BA should include the Load from its Dynamic Schedule as a part of its forecast load to set Frequency Bias requirement. The Native BA should change its Load used to set Frequency Bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

The unique handling of curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale R1:

This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

Rationale R2:

This requirement does not preclude tags from being updated at any time. The requirement specifies conditions under which the tag must be updated.

~~4. None~~

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees ~~Approval~~	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees ~~Approval~~ (Removal of WECC Waiver)	Revised

2	July 21, 2008	Approved by FERC ~~Approval~~	Revised
3	February 6, 2014	Adopted by the NERC Board of Trustees	Revised

A. Introduction

1. **Title:** **Evaluation of Interchange Transactions**

2. **Number:** INT-006-4

3. **Purpose:** To ensure that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Service Provider

5. **Effective Date:**

   First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-006-4 continues to be the reliability assessment of Interchange Transactions prior to their implementation.

   The content of INT-006-4 has been revised and expanded in the following manner:

   - R1 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Balancing Authority must deny the transition.
   - R2 was created by revising R1 from INT-006-3. This requirement ensures that Transmission Service Providers involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Transmission Service Provider must deny the transition.
   - R3 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange.
   - R4 was created by moving and revising R1 from INT-007-1, which has been retired as part of the project. This requirement lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange.

- R5 was created by moving and revising R1 from INT-008-3, which has been retired as part of the project. This requirement lists the entities to which a Sink Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.
- Attachment 1 timing tables for WECC were modified to address scheduling on a 15 minute basis.

Requirements and Measures

R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

M1. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R1)

R2. Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M2. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each Arranged Interchange or emergency Arranged Interchange within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R2)

R3. The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

3.1. If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.

M3. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request and, if applicable, communicated denial to the Reliability Coordinator no more than 10 minutes after the denial. (R3)

R4. Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

- It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

M4. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that, under the conditions in R4, it did not transition an Arranged Interchange to Confirmed Interchange. (R4)

R5. For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

5.1. The Source Balancing Authority,

5.2. Each Intermediate Balancing Authority,

5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,

5.4. Each Transmission Service Provider included in the Arranged Interchange, and

5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

M5. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it notified the entities of the on-time Confirmed Interchange such that the notification was delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D. (R5)

B. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R3, R4, and R5 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R2 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange. OR The Scheduling Path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.
R2	Operations Planning,	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Same-day Operations, Real-time Operations					Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
R3	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
R4	Operations Planning, Same-day Operations,	Lower	N/A	N/A	N/A	The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-time Operations					an Arranged Interchange to Confirmed Interchange.
R5	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Sink Balancing Authority did not notify all of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.	The Sink Balancing Authority did not notify any of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange. OR The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify one or more of the entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Attachment 1 – Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [1] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[2]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[2]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time		≤ 20 minutes from Arranged Interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start

[1] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[2] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

Attachment 1 – Timing Tables

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<10 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is not the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 5 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 6 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[4] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 7 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 8 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 9 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time		By 12:00 PPT of day the Arranged Interchange was received		≥ 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing Interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - All reliability entities involved in the Arranged Interchange are valid.
    - Generation source and Load sink are defined.
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
    - Distribute notification as each entity approves or denies an Arranged Interchange.
    - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
    - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

- Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
  - Receive distribution of Arranged Interchange
  - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
  - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
  - Submit a request to modify Interchange

- While Interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
  - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
  - How to notify others that it is activating the plan
  - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
  - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
  - Delegation of approval rights and proxy actions, if such approaches will be used.
  - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
  - Personnel plans for short-term and extended periods.
  - Training of personnel in the use of the plan.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing

Authority must deny an Arranged Interchange, but Balancing Authorities may deny for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

Rationale for R2:

TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in Requirement R1, Part 2.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3	July 1, 2010	Approved by FERC	Revised
4	February 6, 2014	Adopted by the NERC Board Of Trustees	Revised

A. Introduction

1. **Title:** ~~Response to~~**Evaluation of Interchange** ~~Authority~~**Transactions**

2. **Number:** INT-006-~~3~~4

3. **Purpose:** To ensure that responsible entities conduct a reliability assessment of each Arranged Interchange ~~is checked for reliability~~ before it is implemented.

4. **Applicability:**

   4.1. Balancing Authority~~.~~

   4.2. Transmission Service Provider~~.~~

5. **Effective Date:** ~~July~~

   First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-006-4 continues to be the reliability assessment of Interchange Transactions prior to their implementation.

   The content of INT-006-4 has been revised and expanded in the following manner:

   - R1 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Balancing Authority must deny the transition.

   - R2 was created by revising R1 from INT-006-3. This requirement ensures that Transmission Service Providers involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Transmission Service Provider must deny the transition.

   - R3 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange.

   - ~~5.~~ R4 was created by moving and revising R1 from INT-007-1, ~~2010~~which has been retired as part of the project. This requirement lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange.

- R5 was created by moving and revising R1 from INT-008-3, which has been retired as part of the project. This requirement lists the entities to which a Sink Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.
- Attachment 1 timing tables for WECC were modified to address scheduling on a 15 minute basis.

~~B.~~Requirements and Measures

R1. ~~Prior~~Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the ~~reliability assessment~~time period defined in ~~the timing requirements tables in this standard~~Attachment 1, Column B~~, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI),~~. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~R1.~~1.1. Each Source and ~~to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an~~ Sink Balancing Authority shall deny the Arranged Interchange ~~to a~~or curtail Confirmed Interchange~~.~~[1] if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

~~R1.1.~~Each ~~involved~~ Balancing Authority shall ~~evaluate~~deny the Arranged Interchange ~~with respect to:~~

~~R1.1.1.~~~~Energy profile (ability to support the magnitude of the~~or curtail Confirmed Interchange~~).~~

~~R1.1.2.~~~~Ramp (ability of generation maneuverability to accommodate).~~

~~R1.1.3.~~1.2. if the Scheduling ~~path~~Path (proper connectivity of Adjacent Balancing Authorities~~).~~) between it and its Adjacent Balancing Authorities is invalid.

M1. ~~Each involved~~ Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R1)

R2. Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of

[1] ~~The Balancing Authority and Transmission Service Provider need not provide responses to any other requests.~~

adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M2. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each Arranged Interchange or emergency Arranged Interchange within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R2)

R3. The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

3.1. If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.

M3. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request and, if applicable, communicated denial to the Reliability Coordinator no more than 10 minutes after the denial. (R3)

R4. Each Sink Balancing Authority shall confirm that ~~the transmission service arrangements~~none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

- It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.

- ~~1.2.~~ It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have ~~adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated.~~ communicated their approval of the transition.

~~C.Measures~~

- ~~The Balancing Authority and Transmission Service Provider shall each provide evidence that it responded, relative to transitioning an Arranged Interchange to a Confirmed Interchange, to each On- time Request for Interchange (RFI), and to each Emergency RFI or~~ It is not a Reliability Adjustment ~~RFI from an~~Arranged Interchange ~~Authority within~~, the ~~reliability assessment~~ time period ~~defined~~specified in ~~the Timing Table~~Attachment 1, Column B~~. The~~, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

M4. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that, under the conditions in R4, it did not transition an Arranged Interchange to Confirmed Interchange. (R4)

R5. For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

5.1. The Source Balancing Authority,

5.2. Each Intermediate Balancing Authority,

5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,

5.4. Each Transmission Service Provider included in the Arranged Interchange, and ~~Transmission Service Provider need not provide evidence~~

5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

~~M1.~~M5. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it ~~responded~~notified the entities of the on-time Confirmed Interchange such that the notification was delivered in time to ~~any other requests.~~be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D. (R5)

~~D.~~B. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~ Enforcement Authority

~~1.1.~~ Regional ~~Reliability Organization.~~Entity

~~1.2. Compliance Monitoring Period and Reset Time Frame~~

~~The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.~~

~~1.3.~~1.2. ~~Data~~Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep ~~90 days of historical data. The Compliance Monitor shall keep audit records~~ data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a ~~minimum~~longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R3, R4, and R5 for the most recent three calendar ~~years.~~ months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R2 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaint

1.4. Additional Compliance Information

~~The Balancing Authority and Transmission Service Provider shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.~~

~~Subsequent to the initial compliance review, compliance may be:~~

~~**1.4.1** Verified by audit at least once every three years.~~

~~**1.4.2** Verified by spot checks in years between audits.~~

~~**1.4.3** Verified by annual audits of non-compliant Interchange Authorities, until compliance is demonstrated.~~

~~**1.4.4** Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.~~

~~The Balancing Authority, and Transmission Service Provider shall make the following available for inspection by the Compliance Monitor upon request:~~

~~**1.4.5** For compliance audits and spot checks, relevant data and system log records and agreements for the audit period which indicate a reliability entity identified in R1 responded to all instances of the Interchange Authority's communication under Reliability Standard INT-005 Requirement 1 concerning the pending transition of an Arranged Interchange to Confirmed Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority, or Transmission Service Provider.~~

~~**1.4.6** For specific complaints, agreements and those data and system log records associated with the specific Interchange event contained in the complaint which indicates a reliability entity identified in R1 has responded to the Interchange Authority's communication under INT-005 R1 concerning the pending transition of Arranged Interchange to Confirmed Interchange for that specific Interchange.~~

~~**2. Levels of Non-Compliance**~~

~~**2.1. Level 1:** One occurrence[2] of not responding to the Interchange Authority as described in R1.~~

~~**2.2. Level 2:** Two occurrences[1] of not responding to the Interchange Authority as described in R1.~~

~~**2.3. Level 3:** Three occurrences[1] of not responding to the Interchange Authority as described in R1.~~

~~**2.4. Level 4:** Four or more occurrences[1] of not responding to the Interchange Authority as described in R1 or no evidence provided.~~

~~E. Regional Differences~~

~~None.~~

None

~~[2] This does not include instances of not responding due to extenuating circumstances approved by the Compliance Monitor.~~

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange. OR The Scheduling Path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.
R2	Operations Planning,	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Same-day Operations, Real-time Operations					Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
R3	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
R4	Operations Planning, Same-day Operations,	Lower	N/A	N/A	N/A	The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-time Operations					an Arranged Interchange to Confirmed Interchange.
R5	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Sink Balancing Authority did not notify all of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.	The Sink Balancing Authority did not notify any of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange. OR The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify one or more of the entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Attachment 1 – Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[2]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<15 minutes prior to ramp start and <1 hour after the start time	Late		Entities have up to 10 minutes to respond.		< 3 minutes after receipt of Confirmed Interchange
<1 hour and > 15 minutes prior to ramp start	On-time		< 10 minutes from Arranged Interchange receipt		> 3 minutes prior to ramp start
>1 hour to < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged Interchange receipt		> 39 minutes prior to ramp start
> 4 hours prior to ramp start	On-time		< 2 hours from Arranged Interchange receipt		> 1 hour 58 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[4] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

Attachment 1 – Timing Tables

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [5] is Submitted	Time Classification	Sink BA Makes Initial Distribution of Arranged Interchange[6]	BA and TSP Conduct Reliability Assessments	Compilation and Distribution Status[4]	BA Prepares Confirmed Interchange for Implementation
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<10 minutes prior to ramp start and <1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		< 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and <1 hour after transaction start time where transaction start time is not the top of the hour	Late		Entities have up to 10 minutes to respond.		< 3 minutes after receipt of Confirmed Interchange
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		< 5 minutes from Arranged Interchange receipt		> 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start	On-time		< 6 minutes from Arranged Interchange receipt		> 3 minutes prior to ramp start

[5] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[6] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If Arranged Interchange [5] is Submitted	Time Classification	Sink BA Makes Initial Distribution of Arranged Interchange[6]	BA and TSP Conduct Reliability Assessments	Compilation and Distribution Status[4]	BA Prepares Confirmed Interchange for Implementation
time is at the top of the hour					
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		< 7 minutes from Arranged Interchange receipt		> 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		< 8 minutes from Arranged Interchange receipt		> 3 minutes prior to ramp start
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		< 9 minutes from Arranged Interchange receipt		> 3 minutes prior to ramp start
<1 hour and > 15 minutes prior to ramp start	On-time		< 10 minutes from Arranged Interchange receipt		> 3 minutes prior to ramp start
> 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged interchange receipt		> 39 minutes prior to ramp start
> 4 hours prior to ramp start	On-time		< 2 hours from Arranged Interchange receipt		> 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time > 00:00 PPT of following day	On-time		By 12:00 PPT of day the Arranged Interchange was received		> 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing Interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
  - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
  - All reliability entities involved in the Arranged Interchange are valid.
  - Generation source and Load sink are defined.
  - Megawatt profile is defined.
  - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
  - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
  - Megawatt profile is defined.
  - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
  - Distribute notification as each entity approves or denies an Arranged Interchange.
  - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
  - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.
  - Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
  - Receive distribution of Arranged Interchange
  - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
  - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
  - Submit a request to modify Interchange

- While Interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
  - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
  - How to notify others that it is activating the plan
  - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
  - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
  - Delegation of approval rights and proxy actions, if such approaches will be used.
  - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
  - Personnel plans for short-term and extended periods.
  - Training of personnel in the use of the plan.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

Rationale for R2:

TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in Requirement R1, Part 2.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	~~**Approved by BOT**~~Adopted by the NERC Board Of Trustees	New
2	May 2, 2007	~~**Approved by BOT**~~Adopted by the NERC Board Of Trustees	Revised
3	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3	~~April 8~~July 1, 2010	Approved by FERC~~, Effective July 1, 2010~~	Revised
4	February 6, 2014	Adopted by the NERC Board Of Trustees	Revised

~~Timing Requirements for all Interconnections except WECC~~

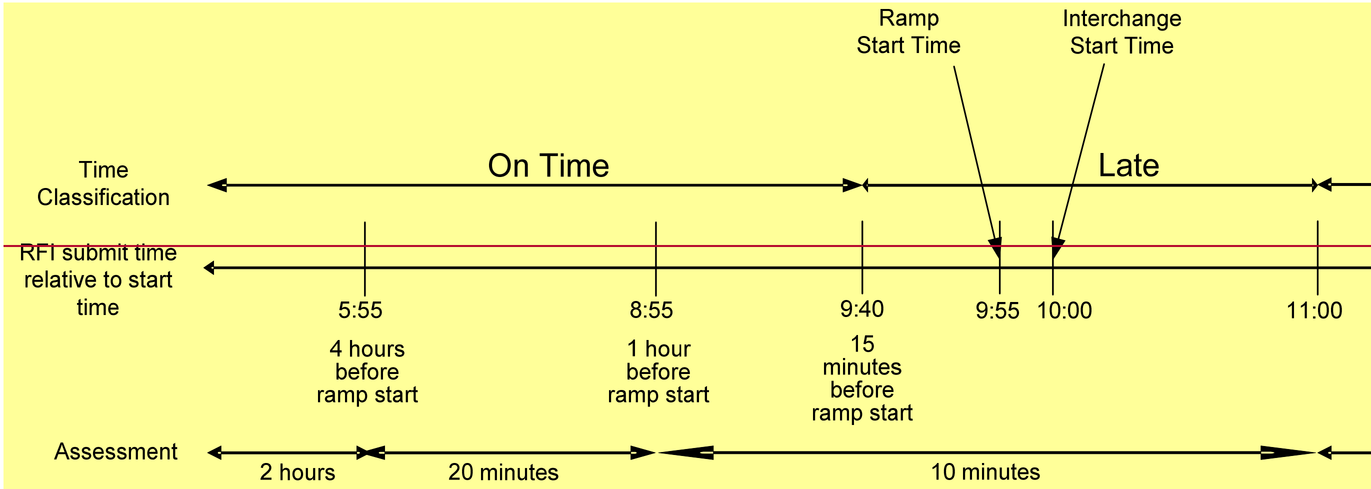
~~Request for Interchange Submitted~~

~~Interchange Timeline with Minimum Reliability-Related Response Times~~

~~If Arranged Interchange (RFI)[7] is Submitted~~	~~IA Assigned Time Classification~~	~~IA Makes Initial Distribution of Arranged Interchange~~	~~BA and TSP Conduct Reliability Assessments~~	~~IA Compiles and Distributes Status~~	~~B... Confirm... for Im...~~
~~>1 hour after the RFI start time~~	~~ATF~~	~~≤ 1 minute from RFI submission~~	~~Entities have up to 2 hours to respond.~~	~~≤ 1 minute from receipt of all Reliability Assessments~~	
~~<15 minutes prior to ramp start and ≤1 hour after the RFI start time~~	~~Late~~	~~≤ 1 minute from RFI submission~~	~~Entities have up to 10 minutes to respond.~~	~~≤ 1 minute from receipt of all Reliability Assessments~~	~~≤ 3... receipt...~~
~~<1 hour and ≥ 15 minutes prior to ramp start~~	~~On-time~~	~~≤ 1 minute from RFI submission~~	~~≤ 10 minutes from Arranged Interchange receipt from IA~~	~~≤ 1 minute from receipt of all Reliability Assessments~~	~~≥ 3 r...~~
~~≥1 hour to < 4 hours prior to ramp start~~	~~On-time~~	~~≤ 1 minute from RFI submission~~	~~≤ 20 minutes from Arranged Interchange receipt from IA~~	~~≤ 1 minute from receipt of all Reliability Assessments~~	~~≥ 39...~~
~~≥ 4 hours prior to ramp start~~	~~On-time~~	~~≤ 1 minute from RFI submission~~	~~≤ 2 hours from Arranged Interchange receipt from IA~~	~~≤ 1 minute from receipt of all Reliability Assessments~~	~~≥ 1 h... prio...~~

[7] ~~Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.~~

~~Example of Timing Requirements for all Interconnections except WECC~~

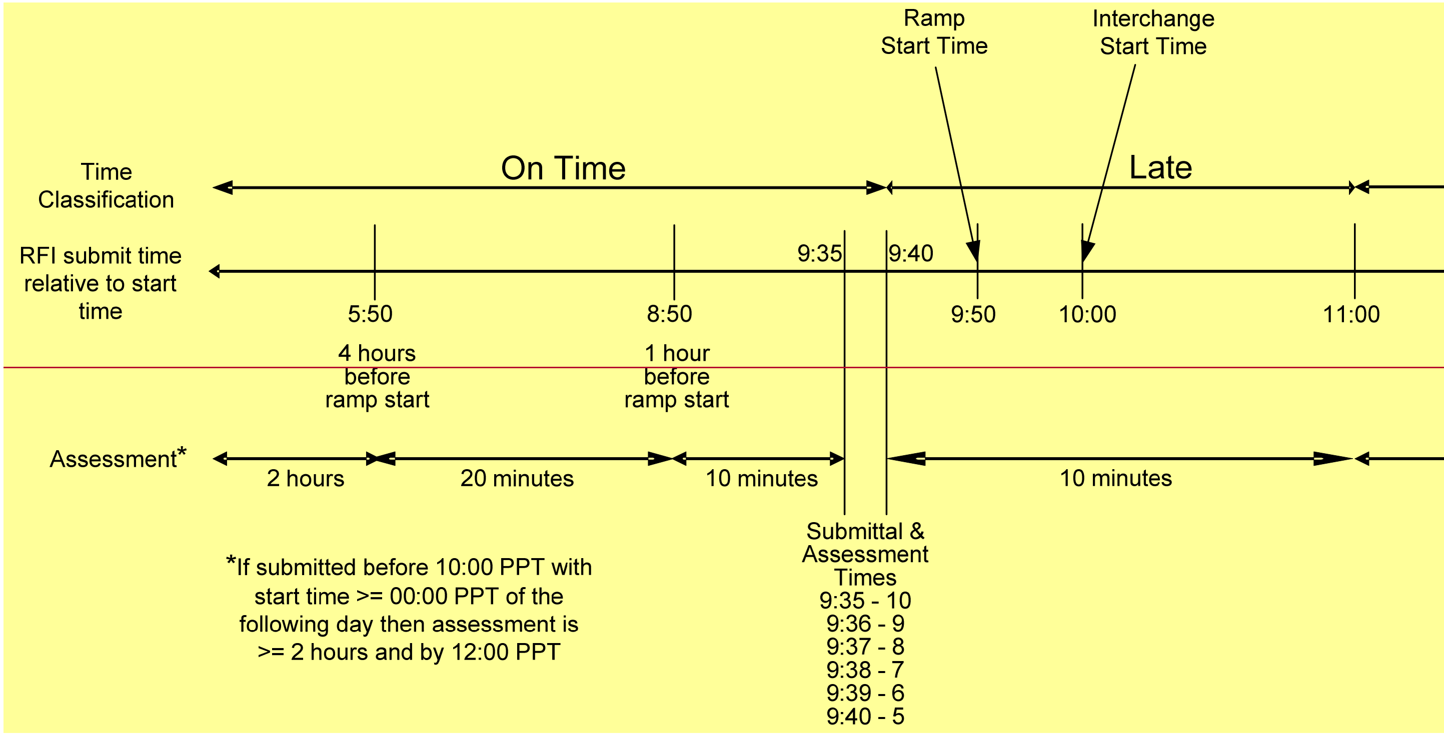


~~Timing Requirements for WECC~~

~~If Arranged Interchange (RFI)[8] is Submitted~~	~~IA Assigned Time Classification~~	~~IA Makes Initial Distribution of Arranged Interchange~~	~~BA and TSP Conduct Reliability Assessments~~	~~IA Compiles and Distributes Status~~	~~BA Prep Inte Imp~~
~~>1 hour after the start time~~	~~ATF~~	~~≤ 1minute from RFI submission~~	~~Entities have up to 2 hours to respond.~~	~~≤ 1minute from receipt of all Reliability Assessments~~	
~~<10 minutes prior to ramp start and ≤1 hour after the start time~~	~~Late~~	~~≤ 1minute from RFI submission~~	~~Entities have up to 10 minutes to respond.~~	~~≤ 1minute from receipt of all Reliability Assessments~~	~~≤ 3 min of c~~
~~10 minutes prior to ramp start~~	~~On-time~~	~~≤ 1minute from RFI submission~~	~~≤ 5 minutes from Arranged Interchange receipt from IA~~	~~≤ 1minute from receipt of all Reliability Assessments~~	~~≥ 3 m r~~
~~11 minutes prior to ramp start~~	~~On-time~~	~~≤ 1minute from RFI submission~~	~~≤ 6 minutes from Arranged Interchange receipt from IA~~	~~≤ 1minute from receipt of all Reliability Assessments~~	~~≥ 3 m r~~
~~12 minutes prior to ramp start~~	~~On-time~~	~~≤ 1minute from RFI submission~~	~~≤ 7 minutes from Arranged Interchange receipt from IA~~	~~≤ 1minute from receipt of all Reliability Assessments~~	~~≥ 3 m r~~
~~13 minutes prior to ramp start~~	~~On-time~~	~~≤ 1minute from RFI submission~~	~~≤ 8 minutes from Arranged Interchange receipt from IA~~	~~≤ 1minute from receipt of all Reliability Assessments~~	~~≥ 3 m r~~
~~14 minutes prior to ramp start~~	~~On-time~~	~~≤ 1minute from RFI submission~~	~~≤ 9 minutes from Arranged Interchange receipt from IA~~	~~≤ 1minute from receipt of all Reliability Assessments~~	~~≥ 3 m r~~
~~<1 hour and ≥ 15 minutes prior to ramp start~~	~~On-time~~	~~≤ 1minute from RFI submission~~	~~≤ 10 minutes from Arranged Interchange receipt from IA~~	~~≤ 1minute from receipt of all Reliability Assessments~~	~~≥ 3 m r~~
~~≥ 1hour and < 4 hours prior to ramp start~~	~~On-time~~	~~≤ 1minute from RFI submission~~	~~< 20 minutes from Arranged interchange receipt from IA~~	~~≤ 1minute from receipt of all Reliability Assessments~~	~~≥ 39 m r~~
~~≥ 4 hours prior to ramp start~~	~~On-time~~	~~≤ 1minute from RFI submission~~	~~≤ 2 hours from Arranged Interchange receipt from IA~~	~~≤ 1minute from receipt of all Reliability Assessments~~	~~≥ 1 ho prior~~
~~Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day~~	~~On-time~~	~~≤ 1minute from RFI submission~~	~~By 12:00 PPT of day the Arranged Interchange was received by the IA~~	~~≤ 1minute from receipt of all Reliability Assessments~~	~~≥ 1 ho prior~~

[8] ~~Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.~~

~~Example of Timing Requirements for WECC~~



A. Introduction

1. **Title: Implementation of Interchange**

2. **Number: INT-009-2**

3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.

4. **Applicability:**

   4.1. Balancing Authority.

5. **Effective Date:**

   The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.

   The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term "Composite Confirmed Interchange" has been introduced.

   The content of INT-009-2 has been revised and expanded in the following manner:

   - R1 was combined with INT-003-3 R1 and modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.
   - R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Actual Net Interchange term for their ACE controls.
   - R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls a high-voltage direct current tie coordinates the Confirmed Interchange.

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

M2. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). (R2)

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2 and R3 for the most recent 3 months plus the current month.

If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange.
R2	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process).
R3	Real-time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R2: R12.3 of BAL-005-2b addresses common metering for Dynamic Schedules and Pseudo-Ties but not their implementation into ACE. Requirement R2 is parallel to R10 of BAL-005-2b which only addresses Dynamic Schedules. Presently, there is a gap in the BAL standards that this requirement fills for Pseudo-Ties.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	February 6, 2014	Adopted by the NERC Board of Trustees	Revised

A. Introduction

1. **Title:** **Implementation of Interchange**

2. **Number:** **INT-009-~~1~~2**

3. **Purpose:** To ensure that ~~the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority such that the~~ Balancing Authorities implement the Interchange ~~exactly~~ as agreed upon in the Interchange confirmation process.

4. **Applicability:**

   4.1. Balancing Authority.

5. **Effective Date:** ~~January 1, 2007~~

~~B. Requirements~~

~~**R1.** The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.~~

~~C. Measures~~

~~**M1.** The Balancing Authority shall provide evidence that Implemented Interchange matches Confirmed Interchange as submitted by the Interchange Authority.~~

~~**M2.** Evidence shall demonstrate that the Interchange was implemented in the Balancing Authority's Area Control Error (ACE) equation, or the system that calculates the ACE equation. Evidence may be on a net basis or an individual Interchange basis.~~

~~**M3.** Balancing Authorities that are interconnected with a direct current tie shall demonstrate that the Interchange was implemented in the ACE equation or modeled as an equivalent generator/load within its area.~~

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.

The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term "Composite Confirmed Interchange" has been introduced.

The content of INT-009-2 has been revised and expanded in the following manner:

- R1 was combined with INT-003-3 R1 and modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.
- R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Actual Net Interchange term for their ACE controls.
- R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls a high-voltage direct current tie coordinates the Confirmed Interchange.

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

M2. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). (R2)

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*, *Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

Regional ~~Reliability Organization.~~Entity

~~1.2. Compliance Monitoring Period and Reset Time Frame~~

~~The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.~~

~~1.3.~~1.2. ~~Data~~Evidence Retention

The Balancing Authority ~~and Interchange Authority~~ shall ~~each~~ keep ~~90 days of historical~~ data~~. The~~ or evidence to show compliance as identified below unless directed by its Compliance ~~Monitor~~Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2 and R3 for the most recent 3 months plus the current month.

If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records ~~for a minimum of three calendar years.~~and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

~~Each Balancing Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.~~

~~Subsequent to the initial compliance review, compliance may be:~~

~~1.4.1 Verified by audit at least once every three years.~~

~~1.4.2 Verified by spot checks in years between audits.~~

~~1.4.3 Verified by annual audits of non-compliant Balancing Authorities, until compliance is demonstrated.~~

~~**1.4.4** Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.~~

~~The Balancing Authorities shall make the following available for inspection by the Compliance Monitor upon request:~~

~~**1.4.5** For compliance audits and spot checks, relevant data and system log records for the audit period which indicate a Balancing Authority implemented all instances of the Interchange Authority's communication under R1 concerning the implementation of a Confirmed Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority~~

~~**1.4.6** For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicates a Balancing Authority implemented the Interchange Authority's communication under R1 concerning the implementation of the Confirmed Interchange for that specific Interchange.~~

~~**2. Levels of Non-Compliance**~~

~~**2.1. Level 1:** One occurrence[1] of not implementing a Confirmed Interchange as described in R1.~~

~~**2.2. Level 2:** Two occurrences[1] of not implementing a Confirmed Interchange as described in R1.~~

~~**2.3. Level 3:** Three occurrences[1] of not implementing a Confirmed Interchange as described in R1.~~

~~**2.4. Level 4:** Four or more occurrences[1] of not implementing a Confirmed Interchange as described in R1 or no evidence provided.~~

~~E. Regional Differences~~

~~None identified.~~

None

~~[1] This does not include instances of not implementing due to extenuating circumstances approved by the Compliance Monitor.~~

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange.
R2	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process).
R3	Real-time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

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D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R2: R12.3 of BAL-005-2b addresses common metering for Dynamic Schedules and Pseudo-Ties but not their implementation into ACE. Requirement R2 is parallel to R10 of BAL-005-2b which only addresses Dynamic Schedules. Presently, there is a gap in the BAL standards that this requirement fills for Pseudo-Ties.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	February 6, 2014	Adopted by the NERC Board of Trustees	Revised

A. Introduction

1. **Title: Interchange Initiation and Modification for Reliability**
2. **Number: INT-010-2**
3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.
4. **Applicability:**

   4.1. Balancing Authority
5. **Effective Date:**

   The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to replace "request for Arranged Interchange" with the correct term "Request for Interchange." A rationale was developed to clarify use of the term "energy sharing agreement" for this requirement.
   - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.

B. Requirements and Measures

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted an RFI per Requirement R1. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed

Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was submitted within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a Request for Interchange was submitted reflecting that Interchange Schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, and R3, for the most recent three calendar months plus the current month.
- If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Request for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that scheduled Interchange.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule Curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the Curtailment.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

This requirement was originally revised to replace the term "Request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Board of Trustees Adoption	New
1	March 16, 2007	FERC Approval	New
2	February 6, 2014	Board of Trustees Adoption	Revised

A. Introduction

1. **Title:** **Interchange ~~Coordination Exemptions~~Initiation and Modification for Reliability**

2. **Number:** **INT-010-~~1~~2**

3. **Purpose:** ~~Allow certain types of~~ To provide guidance for required actions on Confirmed Interchange ~~schedules~~ or Implemented Interchange to ~~be initiated or modified by~~ address reliability ~~entities, and to be exempt from compliance with other Interchange Standards under abnormal operating conditions.~~.

4. **Applicability:**

   4.1. Balancing Authority~~.~~

5. **Effective Date:**

   The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to replace "request for Arranged Interchange" with the correct term "Request for Interchange." A rationale was developed to clarify use of the term "energy sharing agreement" for this requirement.
   - ~~4.2.~~ R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.

~~5. Effective Date: January 1, 2007~~

B. Requirements and Measures

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a ~~request~~Request for ~~an Arranged~~ Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no ~~request for Arranged Interchange~~RFI is required. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

~~**R2.** For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability~~

~~Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event.~~

~~**R3.** For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event.~~

~~C. Measures~~

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted ~~Arranged Interchange~~an RFI per Requirement ~~1.~~R1. (R1)

~~**M2.** The Reliability Coordinator that directs a modification to an existing Interchange shall have evidence that a directive was issued to submit the Arranged Interchange in accordance with Requirement 2.~~

~~**M3.** The Reliability Coordinator that directs the initiation of a new Interchange shall have evidence that a directive was issued to submit the Arranged Interchange in accordance with Requirement 3.~~

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was submitted within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a Request for Interchange was submitted reflecting that Interchange Schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

Regional ~~Reliability Organization.~~ Entity

~~**1.2. Compliance Monitoring Period and Reset Time Frame**~~

~~The Performance-Reset Period shall be twelve months from the last noncompliance to R1, R2, or R3.~~

~~1.3.~~1.2. ~~Data~~Evidence Retention

The Balancing Authority ~~and Reliability Coordinator~~ shall ~~each~~ keep ~~90 days of historical~~ data. ~~The~~ or evidence to show compliance as identified below unless directed by its Compliance ~~Monitor~~Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, and R3, for the most recent three calendar months plus the current month.
- If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records ~~for a minimum of three calendar years.~~and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

~~Each Balancing Authority and Reliability Coordinator shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.~~

~~Subsequent to the initial compliance review, compliance may be:~~

~~**1.4.1** Verified by audit at least once every three years.~~

~~**1.4.2** Verified by spot checks in years between audits.~~

~~**1.4.3** Verified by annual audits of non-compliant Balancing Authorities and Reliability Coordinators, until compliance is demonstrated.~~

~~**1.4.4** Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.~~

~~The Balancing Authority and Reliability Coordinator shall make the following available for inspection by the Compliance Monitor upon request:~~

~~**1.4.5** For compliance audits and spot checks, relevant data and system log records for the audit period which indicate a Balancing Authority or Reliability Coordinator acted in compliance with INT-010. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority~~

~~**1.4.6** For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicates a Balancing Authority or Reliability Coordinator failed to act in compliance with INT-010.~~

~~**2. Levels of Non-Compliance**~~

~~**2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions is present:~~

~~**2.1.1** One occurrence of not submitting an Arranged Interchange as described in R1.~~

~~**2.1.2** One occurrence of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.~~

~~**2.2. Level 2:** There shall be a level two non-compliance if either of the following conditions is present:~~

~~**2.2.1** Two occurrences of not submitting an Arranged Interchange as described in R1.~~

~~**2.2.2** Two occurrences of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.~~

~~**2.3. Level 3:** There shall be a level three non-compliance if either of the following conditions is present:~~

~~**2.3.1** Three occurrences of not submitting an Arranged Interchange as described in R1.~~

~~**2.3.2** Three occurrences of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.~~

~~**2.4. Level 4:** There shall be a level three non-compliance if any of the following conditions is present:~~

~~**2.4.1** Four or more occurrences of not submitting an Arranged Interchange as described in R1.~~

~~**2.4.2** Four or more occurrences of not directing the submittal of a new or modified Arranged Interchange as described in Requirements 2 or 3.~~

~~**2.4.3** No evidence provided.~~

~~E. Regional Differences~~

~~None identified.~~

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Request for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that scheduled Interchange.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule Curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the Curtailment.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

This requirement was originally revised to replace the term "Request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Board of Trustees Adoption	New
1	March 16, 2007	FERC Approval	New
2	February 6, 2014	Board of Trustees Adoption	Revised

A. Introduction

1. **Title:** **Intra-Balancing Authority Transaction Identification**

2. **Number:** INT-011-1

3. **Purpose:** To ensure that transfers within a Balancing Authority Area using Point to Point Transmission Service are communicated and accounted for in congestion management procedures.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Load-Serving Entities

5. **Effective Date:**

   The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   This standard was created in response to a FERC directive in Order 693, paragraph 817: *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

   The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

B. Requirements and Measures

R1. Each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange unless the information about intra-Balancing Authority transfers is included in congestion management procedure(s) via an alternate method. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations]*

M1. Each Load-Serving Entity subject to R1 shall have evidence, such as dated and time-stamped electronic records, documentation of congestion management procedures, or other similar evidence, that a Request for Interchange was submitted for each Point to

Point Transmission Service intra-Balancing Authority transfer subject to R1 or that each intra-Balancing Authority transfer subject to R1 was accounted for in congestion management procedure(s) via an alternate method. (R1)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Load-Serving Entity shall keep data or evidence to show compliance with R1 for the most recent three months plus the current month unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	*Operations Planning, Same-day Operations*	*Lower*	N/A	N/A	N/A	The Load-Serving Entity used Point to Point Transmission Service for an intra-Balancing Authority Area transfer, and did not submit a Request for Interchange for an intra-Balancing Authority transfer that is not included in congestion management procedure(s) via an alternate method.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees	New standard developed

Proposed Definitions for the NERC Glossary of Terms

Project 2008-12: Coordinate Interchange Standards

The Coordinate Interchange Standards Drafting (CISDT) received comments on the proposed set of definitions to be revised or added to the NERC Glossary of Terms. The CISDT made minor clarifying edits of several of the definitions based on these comments. These proposed defined terms are being posted for a final ballot.

Revisions to Defined Terms in the NERC Glossary

- **Request for Interchange -** A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.
- **Arranged Interchange** - The state where a Request for Interchange (initial or revised) has been submitted for approval.
- **Dynamic Interchange Schedule or Dynamic Schedule:** A time-varying energy transfer that is updated in Real-time and included in the Scheduled Net Interchange (NI_S) term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Pseudo-Tie:** A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NI_A) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Confirmed Interchange** - The state where no party has denied and all required parties have approved the Arranged Interchange.
- **Adjacent Balancing Authority** - A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
- **Intermediate Balancing Authority** - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
- **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.
- **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.

- **Operational Planning Analysis:** An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Proposed additional Defined Terms to be added to the NERC Glossary

- **Reliability Adjustment Arranged Interchange** – A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
- **Composite Confirmed Interchange –** The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
- **Attaining Balancing Authority:** A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.
- **Native Balancing Authority:** A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

Proposed Definitions for the NERC Glossary of Terms

Project 2008-12: Coordinate Interchange Standards

The Coordinate Interchange Standards Drafting (CISDT) received comments on the proposed set of definitions to be revised or added to the NERC Glossary of Terms. The CISDT made minor clarifying edits of several of the definitions based on these comments. These proposed defined terms are being posted for a final ballot.

Revisions to Defined Terms in the NERC Glossary

Request for Interchange (RFI) - A collection of data as defined in the NAESB Business Practice Standards ~~RFI Datasheet, to be~~ submitted ~~to the Interchange Authority~~ for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or an energy transfer within a single Balancing Authority.

Arranged Interchange - The state where a Request for Interchange (initial or revised) has been submitted for approval. ~~the Interchange Authority has received the Interchange information (initial or revised).~~

Dynamic Interchange Schedule or Dynamic Schedule: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in R~~r~~eal-time and ~~used~~ included in the Net Interchange Schedule term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes). ~~as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.~~

Pseudo-Tie: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in R~~r~~eal-time and included in the Net Interchange Actual (NI_A) term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).~~used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.~~

Confirmed Interchange - The state where no party has denied and all required parties have approved ~~the Interchange Authority has verified~~ the Arranged Interchange.

Adjacent Balancing Authority - A Balancing Authority Area whose Balancing Authority Area ~~that~~ is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

Intermediate Balancing Authority - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority. ~~Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.~~

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule. ~~(This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)~~

Source Balancing Authority - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule. ~~(This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)~~

Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Proposed additional Defined Terms to be added to the NERC Glossary

- **Reliability Adjustment Arranged Interchange** – A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
- **Composite Confirmed Interchange –** The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
- **Attaining Balancing Authority:** A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.
- **Native Balancing Authority:** A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

Exhibit B

Implementation Plan for Proposed Reliability Standards and Definitions

Implementation Plan

Project 2008-12: Coordinate Interchange Standards

Requested Approvals

- INT-004-3 — Dynamic Transfers
- INT-006-4 — Evaluation of Interchange Transactions
- INT-009-2 — Implementation of Interchange
- INT-010-2 — Interchange Initiation and Modification for Reliability
- INT-011-1 — Intra-Balancing Authority Transaction Identification

Requested Retirements

- INT-001-3 Interchange Information
- INT-003-3 Interchange Transaction Implementation
- INT-004-2 Dynamic Interchange Transaction Modifications
- INT-005-3 Interchange Authority Distributes Arranged Interchange
- INT-006-3 Response to Interchange Authority
- INT-007-1 Interchange Confirmation
- INT-008-3 Interchange Authority Distributes Status
- INT-009-1 Implementation of Interchange
- INT-010-1 Interchange Coordination Exemptions

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

- **Dynamic Interchange Schedule or Dynamic Schedule:** A time-varying energy transfer that is updated in Real-time and included in the Net Interchange Schedule term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Pseudo-Tie:** A time-varying energy transfer that is updated in Real-time and included in the Net Interchange Actual term (NI_A) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

- **Request for Interchange** - A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.
- **Arranged Interchange** - The state where a Request for Interchange (initial or revised) has been submitted for approval.
- **Confirmed Interchange** - The state where no party has denied and all required parties have approved the Arranged Interchange.
- **Adjacent Balancing Authority** - A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
- **Intermediate Balancing Authority** - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
- **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.
- **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.
- **Operational Planning Analysis:** An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Proposed additional Defined Terms to be added to the NERC Glossary

- **Reliability Adjustment Arranged Interchange** – A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
- **Composite Confirmed Interchange –** The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
- **Attaining Balancing Authority:** A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.
- **Native Balancing Area:** A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

Background

The standards were developed under Project 2008-12, Coordinate Interchange Standards. The drafting team revised the existing approved standards and grouped the requirements in distinct groupings within each standard. The drafting team developed a new standard, INT-011-1, Intra-Balancing Authority Transaction Identification, in response to a FERC directive in Order 693, paragraph 817:

> *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

The proposed revision to the definition of Operational Planning Analysis addresses a FERC Order 693 directive:

> *866. Accordingly, the Commission approves Reliability Standard INT-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.*

The Reliability Coordinator and Transmission Operator are required to perform an Operational Planning Analysis in existing IRO-008-1, Requirement R1 and in TOP-002-3, Requirement R1 which was filed with FERC on April 16, 2013. By including the term "Interchange" explicitly in the definition, the drafting team has addressed the directive.

Applicable Entities

- Balancing Authority
- Transmission Service Provider
- Load-Serving Entities
- Purchasing-Selling Entity

Effective Date

First day of the second calendar quarter beyond the date each standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date each standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

Midnight of the day immediately prior to the Effective Date of the new standards in the particular jurisdiction in which the new standards are becoming effective.

Implementation Plan for Definitions

Entities shall use all proposed definitions when implementing any requirements within the new standards which use the defined term(s).

Implementation Plan for INT-004-3, Requirement R3

Requirement R3 is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. A request to revise the NAESB Electric Industry Registry has already been submitted for implementation. This requirement will become effective on the first calendar day two calendar quarters after the NAESB Electric Industry Registry is able to accept Pseudo-Tie registrations. All existing and future Pseudo-Ties are to be registered in the NAESB Electric Industry Registry.

Exhibit C

Order No. 672 Criteria for Proposed Reliability Standards and Definitions

Exhibit C

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

The proposed Reliability Standards achieve specific reliability goals. Proposed Reliability Standard INT-004-3– Dynamic Transfers, ensures that Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures. Proposed Reliability Standard INT-006-4– Evaluation of Interchange Transactions, ensures that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented. Proposed Reliability Standard INT-009-2– Implementation of Interchange, ensures that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process. Proposed Reliability Standard INT-010-2– Interchange

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

Initiation and Modification for Reliability, provides guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability. Proposed Reliability Standard INT-011-1– Intra-Balancing Authority Transaction Identification, ensures that transfers within a Balancing Authority Area using Point-to-Point Transmission Service are communicated and accounted for in congestion management procedures.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

Proposed Reliability Standard INT-004-3– Dynamic Transfers, applies to Balancing Authorities and Purchasing-Selling Entities and is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The requirements clearly state who is required to comply with the standard.

Proposed Reliability Standard INT-006-4– Evaluation of Interchange Transactions, applies to Balancing Authorities and Transmission Service Providers and is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The requirements clearly state who is required to comply with the standard.

Proposed Reliability Standard INT-009-2– Implementation of Interchange, applies to Balancing Authorities and is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The requirements clearly state who is required to comply with the standard.

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[3] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

Proposed Reliability Standard INT-010-2– Interchange Initiation and Modification for Reliability, applies to Balancing Authorities and is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The requirements clearly state who is required to comply with the standard.

Proposed Reliability Standard INT-011-1– Intra-Balancing Authority Transaction Identification, applies to Load-Serving Entities and is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The requirements clearly state who is required to comply with the standard.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The VRFs and VSLs for each of the proposed standards comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding Requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non preferential manner. [5]

[4] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

[5] Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

The proposed Reliability Standards contain measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help provide clarity regarding how the requirements will be enforced, and ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standards achieve the reliability goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standards improve reliability by making transactions more apparent for reliability assessments and by clarifying which functional entities perform Interchange Authority tasks. Collectively, the proposed five Reliability Standards also consolidate this body of standards.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

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[6] Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

[7] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed Reliability Standards and definitions do not reflect a "lowest common denominator" approach. To the contrary, the proposed Standards and definitions represent a significant improvement over the previous versions as described herein.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]

The proposed Reliability Standards and definitions apply throughout North America and do not favor one geographic area or regional model.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

The proposed Reliability Standards and definitions do not restrict the available transmission capability or limit use of the bulk-power system in a preferential manner.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

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[8] Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

[9] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

[10] Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

The proposed effective dates for the proposed Reliability Standards and definitions are just and reasonable and appropriately balance the urgency in the need to implement the standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability.

This will allow applicable entities adequate time to ensure compliance with the requirements. The proposed effective dates are explained in the proposed Implementation Plan, attached as **Exhibit B**.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standards and definitions were developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards. **Exhibit H** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the standard.

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The initial and recirculation ballots both achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

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[11] Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

[12] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

NERC has identified no competing public interests regarding the request for approval of these proposed Reliability Standards and definitions. No comments were received that indicated the proposed Standards and definitions conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

[13] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit D

Mapping Document

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2008-12 - Coordinate Interchange Standards

Mapping Document

Project Purpose

The purpose of Project 2008-12 is to revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange. The drafting team also addressed the Interchange Subcommittee concerns related to the dynamic Transfers and Pseudo-ties and addressed previously identified stakeholder comments and applicable directives from Order 693. These issues and directives include defining communications on reloading interchange transactions due to different operational conditions and to bringing the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for: **R1.1.** All Dynamic Schedules at the expected average MW profile for each hour.	Revised and Moved into INT-004-3	**INT-004-3:** **R1.** Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1]

[1] Please refer to the timing tables of INT-006-4.

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Independent Expert Review recommendation: Retain Requirement.		Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*] [1] Please refer to the timing tables of INT-006-4. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.
R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority: **R2.1.** If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator. **R2.2.** For each bilateral Inadvertent	Retired	The CI SDT believes that this requirement is no longer necessary for reliability. Since the proposed INT-009-2 R1 makes it clear that the Net Scheduled Interchange term in the control equation can only include Confirmed Interchange as agreed to between Balancing Authorities, this by definition requires that an Arranged Interchange be created in order to implement the schedules listed in

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Interchange payback. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		R2.1 and R2.2. From a reliability perspective, it is unimportant who creates these Arranged interchanges – only that they be created and confirmed prior to being entered into the control equation. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. **R1.1.** The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including:	Revised and Moved into INT-009-2	**INT-009-2:** R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1.1.1. Interchange Schedule start and end time. **R1.1.2.** Energy profile. **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. Independent Expert Review recommendation: Retain Requirement.		in the Composite Confirmed Interchange, is: [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority. R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual (NI_A) term of their respective control ACE (or alternate control process). [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] R3. Each Balancing Authority in whose area the HVDC tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie. [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations, Operations Planning]

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority. Independent Expert Review recommendation: Retire	Retired	The CI SDT believes that at a minimum, this requirement does not belong in the "Dynamic Schedules" standard. However, for several reasons, the CI SDT further believes that this specific requirement is no longer required: • It mandates a practice (releasing of E-Tag limits) that is process related. • The practice is already addressed in related NAESB standards (WEQ-004 Appendix B - E-Tag Actions).

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
per P81 criteria. A guideline exists in the functional specification for electronic tagging.		• Use of a limit (and the associated release of that limit) is only one particular way to address curtailments. Other ways exist that could be used in lieu of this approach. The reliability standard should not mandate a single approach when others may suffice. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.
R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs: **R2.1.** The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +10%. **R2.2.** The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated	Revised	**INT-004-3** **R2.** The Purchasing-Selling Entity that submits a Request for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same Day Operations, Real Time Operations] **2.1.** For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
on the tag by more than +25 megawatt-hours. **R2.3.** A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		that deviation is expected to persist. **2.2.** For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist. **2.3.** The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange. CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have the RFI updated for a Dynamic Schedule or Pseudo-Tie that is significantly different than the original schedule. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis.

Standard: INT-005-3, Interchange Authority Distributes Arranged Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange. **R1.1.** When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Retired	The CISDT is proposing retirement of this requirement. The entities to receive the transaction are included today in the eTag specification, Section 3.6.1.1.1. The timing requirement for the distribution of tags is removed from this standard, as they are currently included and expected to remain in the NAESB documentation. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange. **R1.1.** Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to: **R1.1.1.** Energy profile (ability to support the magnitude of the Interchange). **R1.1.2.** Ramp (ability of generation maneuverability to accommodate). **R1.1.3.** Scheduling path (proper connectivity of Adjacent Balancing Authorities). **R1.2.** Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the	Revised	R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange. 1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid. R2. Each Transmission Service Provider shall approve

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid. CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that this distribution requirement may currently drive how software performs this function. However, if that software were not present, this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		interchange to occur.

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following: **R1.1.** Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate). **R1.2.** All reliability entities involved in the Arranged Interchange are currently in the NERC registry. **R1.3.** The following are defined: **R1.3.1.** Generation source and load sink. **R1.3.2.** Megawatt profile. **R1.3.3.** Ramp start and stop times. **R1.3.4.** Interchange duration. **R1.4.** Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.	Retired, Revisions made to defined term used in various INT standards to clarify reliability objective	R1.1, R1.2 and R1.3 ensure the data submitted on the interchange is valid. This activity occurs in software validation and is not appropriate for a reliability standard; these items are included in the Technical Basis and Guidelines section of INT-006. Interchange that does not meet these criteria would not be an Arranged Interchange. R1.4. is addressed in the proposed revision to the definition of Confirmed Interchange: *The state where no party has denied and all required parties have approved the Arranged Interchange.* INT-006-4, Requirement R4 also specifies conditions under which the BA shall not transition to Confirmed Interchange: R4. Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: [Violation Risk Factor: Lower] [Time

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		Horizon: Operations Planning, Same-day Operations, Real-time Operations] • It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition. • It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition. • It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-008-3, Interchange Authority Distributes Status		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange. **R1.1.** For Confirmed Interchange, the Interchange Authority shall also communicate: **R1.1.1.** Start and stop times, ramps, and megawatt profile to Balancing Authorities. **R1.1.2.** Necessary Interchange information to NERC-identified reliability analysis services. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised and moved into INT-006-4	**INT-006-4:** R5. Each Sink Balancing Authority shall distribute all notifications of whether an Arranged Interchange was transitioned to Confirmed Interchange to the following entities, and notifications of on-time Confirmed Interchange shall be distributed such that they are delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 5.1. The Source Balancing Authority, 5.2. Each Intermediate Balancing Authority, 5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange, 5.4. Each Transmission Service Provider included in the Arranged Interchange, and 5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

Standard: INT-008-3, Interchange Authority Distributes Status		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that this distribution requirement may currently drive how software performs this function. However, if that software were not present, this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the interchange to occur.

Standard: INT-009-1, Implementation of Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Combined with INT-003-3, Requirement R1	**INT-009-2** **R1.** Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs that a separate requirement is not necessary. This requirement was combined with INT-003-3, Requirement R1.

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised	**INT-010-2:** **R1.** The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R2. For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised	**INT-010-2:** **R2.** Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis
R3. For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent	Revised	**INT-010-2:**

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		**R3.** Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis

Exhibit E

White Paper on Order No. 693 Directive, Paragraph 866

Order 693 Paragraph 866

Project 2008-12 Coordinate Interchange Standard Drafting Team Solution
June 2013 (revised December 2013)

In Order No. 693, FERC issued several directives pertaining to the INT standards. This white paper explains how the Coordinate Interchange Standard Drafting Team (CISDT) proposes to address one of those directives through an equal and effective alternative.

Paragraph 866:

> *866. Accordingly, the Commission approves Reliability Standard INT-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.*

Based on feedback from the NERC Operating Committee as well as drafting team input, the CISDT proposes an equally efficient and effective method to address the directive, by revising an existing, approved NERC Glossary term, Operational Planning Analysis. The CISDT proposes revising the term as follows:

> **Operational Planning Analysis**: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

The term **Operational Planning Analysis** is used in standards that apply to both the Reliability Coordinator and the Transmission Operator entities.[1] Proposed Reliability Standard INT-006-4, Requirement R6 requires Interchange information to be provided to the Reliability Coordinator. This is typically achieved using the electronic tagging function.

> *R6.Each Sink Balancing Authority shall distribute all notifications of whether an Arranged*

[1] A comprehensive list of each Reliability Standard and Requirement that contains the tem Operational Planning Analysis is at the end of this document.

Interchange was transitioned to Confirmed Interchange to the following entities, and notifications of on-time Confirmed Interchange shall be distributed such that they are delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]

6.1. The Source Balancing Authority,

6.2. Each Intermediate Balancing Authority,

6.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,

6.4. Each Transmission Service Provider included in the Arranged Interchange, and

6.5. Each Purchasing Selling Entity included in the Arranged Interchange.

The IRO standards apply to the Reliability Coordinator, and Operational Planning Analysis is referenced in the requirements of IRO-008-1. Requirement R1 of IRO-008-1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis:

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions. (Violation Risk Factor: Medium) (Time Horizon: Operations Planning)

By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider Interchange when performing the study. When the results of this study indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3 of IRO-008-1:

R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions. (Violation Risk Factor: Medium) (Time Horizon: Real-time Operations or Same Day Operations)

TOP-002-3 contains requirement for the Transmission Operator to perform an Operational Planning Analysis (Requirement R1) and to develop plans for reliable operations based on the results of the Operational Planning Analysis and notify other entities as to their role in those plans (Requirement R3).

R1. Each Transmission Operator shall have an ***Operational Planning Analysis*** *that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall ***develop a plan*** *to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its*

Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]
R3. Each Transmission Operator ***shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).*** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

While the INT standards do not require Interchange information to be provided to the Transmission Operator, it is expected that the Transmission Operator will rely on TOP-003-2, Requirements R1, R3, and R5 to obtain the information from Balancing Authorities.

R1. Each Transmission Operator shall create a documented specification for the ***data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.*** *The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.

1.2. A mutually-agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R3. Each Transmission Operator shall ***distribute its data specification, as developed in Requirement R1 to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process*** *used in meeting its NERC-mandated reliability requirements. [Violation Risk Factor: Low] [Time Horizon: Operations Planning]*
R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 ***shall satisfy the obligations of the documented specifications for data****. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The IRO standards shown above are mandatory and enforceable. The TOP standards are pending before FERC.

List of Requirements Containing the Term Operational Planning Analysis

Mandatory and Enforceable Standards:

- **IRO-008-1 – Reliability Coordinator Operational Analyses and Real-time Assessments, Requirements R1 and R3:**

  R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions. (Violation Risk Factor: Medium) (Time Horizon: Operations Planning)

  R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions. (Violation Risk Factor: Medium) (Time Horizon: Real-time Operations or Same Day Operations)

Board-approved Standards Pending Regulatory Approval

- **IRO-005-4 — Reliability Coordination — Current Day Operations, Requirement R1:**

  R1.When the results of an ***Operational Planning Analysis*** *or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area. [Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same Day Operations and Operations Planning]*
- **TOP-001-2 — Transmission Operations, Requirements R1 and R8:**

  R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: High] [Time Horizon: Operations Planning,]

  R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]
- **TOP-002-3 — Operations Planning, Requirements R1 and R2:**

  R1. Each Transmission Operator shall have an ***Operational Planning Analysis*** *that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

- **TOP-003-2 — Operational Reliability Data, Requirements R1 and R3:**

  R1. Each Transmission Operator shall create a documented specification for the ***data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.*** *The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

  1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.

  1.2. A mutually-agreeable format.

  1.3. A periodicity for providing data.

  1.4. The deadline by which the respondent is to provide the indicated data.

  R3. Each Transmission Operator shall distribute its data specification, as developed in Requirement R1, to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated Reliability requirements. [Violation Risk Factor: Low] [Time Horizon: Operations Planning]

Exhibit F

Analysis of Proposed Definitions

Proposed Definitions for the NERC Glossary of Terms

Project 2008-12: Coordinate Interchange Standards

The Coordinate Interchange Standards Drafting (CISDT) proposes revisions to ten (10) defined terms in the NERC Glossary of Terms. The CISDT also proposes four (4) new defined terms to be included in the Glossary. These defined terms are used in the INT family of standards and in a few other standards as discussed below.

Proposed revised definitions (redlined):

Dynamic Interchange Schedule or Dynamic Schedule: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in ~~r~~Real-time and ~~used~~ included in the Net Interchange Schedule term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes). ~~as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.~~

> This defined term was revised to provide clarity that a **Dynamic Schedule** is updated in Real-time and is included in the Net Interchange Schedule term in the affected Balancing Authorities' control ACE equations (or alternate control processes). Dynamic Schedules are commonly used for scheduling jointly owned generation to or from another Balancing Authority Area. The revisions to this defined term align with the NERC's Dynamic Transfer Reference Guidelines, (Version 2). This document states (page85):
>
> > A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between BAs. A dynamic schedule typically does not change a BA's operational responsibility; that is, the native BA continues to exercise operational control over, and provides basic BA services to, the dynamically scheduled resources.
> >
> > Dynamic schedules are to be accounted for as interchange schedules by the source, sink, and contract intermediary BA(s), both in their respective ACE equations, and throughout all of their energy accounting processes. Requirement to incorporate into the contract intermediary BA's ACE is subject to regional procedures.
>
> This defined term is also used in BAL-002-WECC, BAL-003-0.1b and BAL-005-0.2b. BAL-003-0.1b will be superseded by BAL-003-1 when it becomes effective April 1, 2015. This defined term is not used in BAL-003-1. It is also contained in the defined term "Reporting ACE" as part of the NIS (Scheduled Net Interchange) term. The "Reporting ACE" definition has not

been approved by FERC. The revisions to this defined term do not change the intent of the requirements in which it is used. The revisions provide additional clarity for these requirements.

Pseudo-Tie: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in R~~r~~eal-time and included in the Net Interchange Actual (NI_A) term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).~~used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.~~

This defined term was revised to provide clarity that a **Pseudo-Tie** is updated in Real-time and is included in the Net Interchange Actual (NI_A) term in the affected Balancing Authorities' control ACE equations (or alternate control processes). Pseudo-Ties are commonly used as a "virtual" tie line flow in the ACE equation but for which no physical tie or energy metering actually exists. The revisions to this defined term align with the NERC's Dynamic Transfer Reference Guidelines, (Version 2). This document states (page 87):

> Pseudo-ties are often employed to assign generators, loads, or both from the BA to which they are physically connected into a BA that has effective operational control of them. Thus, pseudo-ties often provide for change of BA operational responsibility from the native to the attaining BA and at the same time make the attaining BA provider of BA services. In practice, pseudo-ties may be implemented based upon metered or calculated values. All BAs involved account for the power exchange and associated transmission losses as actual interchange between the BAs, both in their ACE equations and throughout all of their energy accounting processes.

This defined term is also used in BAL-002-WECC, BAL-003-0.1b and BAL-005-0.2b. BAL-003-0.1b will be superseded by BAL-003-1 when it becomes effective April 1, 2015. This defined term is not used in BAL-003-1. The revisions to this defined term do not change the intent of the requirements in which it is used. The revisions provide additional clarity for these requirements.

Request for Interchange (RFI) - A collection of data as defined in the NAESB Business Practice Standards ~~RFI Datasheet, to be~~ submitted ~~to the Interchange Authority~~ for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or an energy transfer within a single Balancing Authority.

This defined term is also contained in the defined term "Emergency Request for Interchange" and the revisions to this defined term do not change the intent of the "Emergency Request for Interchange". By removing references to the Interchange Authority, this definition is now based solely on NAESB Business Practice Standards and definitions rather than any entity that may be responsible for its application for reliability.

Arranged Interchange - The state where a Request for Interchange (initial or revised) has been submitted for approval. ~~the Interchange Authority has received the Interchange information (initial or revised).~~

> This defined term is also in MOD-004-1, R11 and R12; also in the "Confirmed Interchange" definition which is also revised under this project. MOD-004-1 was retired under Project 2012-05. Its requirements were incorporated into MOD-001-2, which passed ballot December 20, 2013. This term is not used in the new standard. By removing references to the Interchange Authority, this definition is now based solely on NAESB Business Practice Standards and definitions rather than any entity that may be responsible for its application for reliability. The revisions to this defined term do not change the intent of the requirements or defined terms in which it is used. The revisions provide additional clarity for these requirements and defined terms.

Confirmed Interchange - The state where no party has denied and all required parties have approved ~~the Interchange Authority has verified~~ the Arranged Interchange.

> This defined term is also in definition of "Implemented Interchange". By removing references to the Interchange Authority, this definition is now based solely on NAESB Business Practice Standards and definitions rather than any entity that may be responsible for its application for reliability. The revisions to this defined term do not change the intent of the other defined term in which it is used. The revisions provide additional clarity for that defined term.
>
> The defined terms **Request for Interchange (RFI), Arranged Interchange and Confirmed Interchange** are necessary to define the various stages of creation through implementation of Interchange. These defined terms were revised to better align with industry expectations and NAESB business practices.

Adjacent Balancing Authority - A Balancing Authority Area whose Balancing Authority Area ~~that~~ is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

> This defined term is also BAL-002-1a (Interpretation); BAL-005-0.2b (R9, R14); BAL-006-2 (R2, R3, R4); COM-001-2 R5, R6 (not FERC approved); EOP-001-2.1b (Interpretation); Defined terms "Net Actual Interchange" (contains "Adjacent BA Area"), Net Interchange Schedule" and "Reserve Sharing Group".

Intermediate Balancing Authority - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority. ~~Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.~~

This defined term is also BAL-006-2 but only in the Compliance Monitoring Process section (Section D, item 1.1)

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule. ~~(This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)~~

This defined term is also BAL-002-WECC; BAL-006-2 but only in the Compliance Monitoring Process section (Section D, item 1.1); IRO-006-EAST, R3.3; Definition of “RFI” and WECC term “Contributing Schedule” and “Relief Requirement”.

Source Balancing Authority - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule. ~~(This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)~~

This defined term is also BAL-002-WECC; BAL-006-2; IRO-006-EAST-1 (R3.3); Definitions of “Request for Interchange” and the WECC term “Contributing Schedule”.

The defined terms **Adjacent Balancing Authority, Intermediate Balancing Authority, Sink Balancing Authority and Source Balancing Authority** are necessary to define the various Balancing Authorities involved in the implementation of Interchange and their relationships with regards to Interchange. These defined terms were revised to better align with industry expectations and NAESB business practices.

Operational Planning Analysis: An analysis of the expected system conditions for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

This defined term was revised to meet a FERC Order 693 Directive (paragraph 866) and is used in IRO-008-1 - Reliability Coordinator Operational Analyses and Real-time Assessments. Requirement R1 specifies that the Reliability Coordinator must perform an **Operational Planning Analysis**. By explicitly including “Interchange” in the definition of Operational Planning Analysis, the Reliability Coordinator must consider interchange when performing the study. Further, Requirement R2 specifies that the Reliability Coordinator must perform a Real-time Assessment. By explicitly including “Interchange” in the definition of Real-time Assessment, the Reliability Coordinator must consider interchange when performing the study. When the results of either of these studies indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3.

Proposed new definitions:

Reliability Adjustment Arranged Interchange – A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

The defined term **Reliability Adjustment Arrange Interchange** was developed to accurately reflect the types of Interchange that are adjusted for reliability reasons by a Reliability Coordinator or Transmission Operator. This defined term aligns with industry expectations and NAESB business practices.

Composite Confirmed Interchange – The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.

The defined term **Composite Confirmed Interchange** was developed to define what is to be included in INT-009-2, Requirement R1 to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities. This defined term aligns with industry expectations and NAESB business practices.

Attaining Balancing Authority: A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.

Native Balancing Authority: A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

The defined terms **Attaining Balancing Authority and Native Balancing Authority** are necessary to define the various Balancing Authorities involved in the implementation of Dynamic Transfers and their relationships with regards to Dynamic Transfers. These defined terms were developed to align with industry expectations and NAESB business practices.

Exhibit G

Analysis of Violation Risk Factors and Violation Security Levels

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VRF and VSL Justifications for INT-004-3

VRF and VSL Justifications – INT-004-3, R1	
Proposed VRF	Lower
NERC VRF Discussion	Dynamic Schedules or Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring Arranged Interchanges is submitted, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.

VRF and VSL Justifications – INT-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to submit a Request for Interchange.

VRF and VSL Justifications – INT-004-3, R2	
Proposed VRF	Lower
NERC VRF Discussion	Dynamic Schedules or Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-004-2, R2, which deals with updating tagging information and is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1-2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-004-3, R2	
Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to ensure the Confirmed Interchange or Pseudo-Tie was updated for the next available scheduling hour or future hours.

VRF and VSL Justifications – INT-004-3, R3	
Proposed VRF	Lower
NERC VRF Discussion	Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring Arranged Interchanges is submitted, is assigned a Lower VRF. Also, INT-004-3, R1, which deals with submittal of RFI, is also assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority implemented or operated a Pseudo-Tie for that was not included in the NAESB Electric Industry Registry publication.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	This guideline is not applicable because this is a new requirement.

VRF and VSL Justifications – INT-004-3, R3	
the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to implement or operate a Pseudo-Tie in the NASEB Electric Industry Registry publication.

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VRF and VSL Justifications for INT-006-4

VRF and VSL Justifications – INT-006-4, R1	
Proposed VRF	Lower
NERC VRF Discussion	Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-006-3, R1, which deals with responding to on-time RFI, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR

VRF and VSL Justifications – INT-006-4, R1	
	The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange. OR The Scheduling Path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned “Severe.” Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-006-4, R1	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to take action on an on-time Arranged Interchange or an emergency Arranged Interchange, or for failing to deny an Arranged Interchange under certain circumstances.

VRF and VSL Justifications – INT-006-4, R2	
Proposed VRF	Lower
NERC VRF Discussion	Transmission Service Providers must take action on a received Arranged Interchange within a certain time frame. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-006-3, R1, which deals with responding to on-time RFI, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – INT-006-4, R2	
Proposed High VSL	N/A
Proposed Severe VSL	The Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-006-4, R2	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to take action on an on-time Arranged Interchange or an emergency Arranged Interchange, or for failing to deny an Arranged Interchange or curtail Confirmed Interchange under certain circumstances.

VRF and VSL Justifications – INT-006-4, R3	
Proposed VRF	Lower
NERC VRF Discussion	Source or Sink Balancing Authorities receiving a Reliability Adjustment Arranged Interchange need to approve or deny it prior to the expiration of the reliability assessment period defined in the timing requirements. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-006-3, R1, which deals with approving or denying Arranged Interchange is submitted, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A

VRF and VSL Justifications – INT-006-4, R3	
Proposed Moderate VSL	N/A
Proposed High VSL	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.
Proposed Severe VSL	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: Not applicable. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-006-4, R3	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to act on a Reliability Adjustment Arranged Interchange within a certain time frame, or for failing to communicate a denial to the Reliability Coordinator within 10 minutes of the denial.

VRF and VSL Justifications – INT-006-4, R4	
Proposed VRF	Lower
NERC VRF Discussion	Balancing Authorities should not transition Arranged Interchange to Confirmed Interchange under certain conditions. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-007-13, R1, which deals with ensuring Arranged Interchanges is valid before transitioning to Confirmed Interchange, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A

VRF and VSL Justifications – INT-006-4, R4	
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning an Arranged Interchange to Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of	The VSL is assigned for a single instance of transitioning an Arranged Interchange to Confirmed Interchange under certain circumstances under which an Interchange should not be transitioned.

VRF and VSL Justifications – INT-006-4, R4	
Violations	

VRF and VSL Justifications – INT-006-4, R5	
Proposed VRF	Lower
NERC VRF Discussion	Distributing information regarding whether an Arranged Interchange was transitioned to Confirmed Interchange is necessary to ensure that everyone has the same information regarding the transactions. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-008-3, R1, which deals with distributing information regarding whether an Arranged Interchange was transitioned to Confirmed Interchange, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	The Sink Balancing Authority did not distribute notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to all of the entities listed in Requirement R5 Parts 5.1-5.5.

VRF and VSL Justifications – INT-006-4, R5	
Proposed Severe VSL	The Sink Balancing Authority did not notify any of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange. OR The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify one or more of the entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: Not applicable. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4	The VSL is assigned for a single instance of failing to distribute

VRF and VSL Justifications – INT-006-4, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to specific entities.

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VRF and VSL Justifications for INT-009-2

VRF and VSL Justifications – INT-009-2, R1	
Proposed VRF	Medium
NERC VRF Discussion	Agreement between Balancing Authorities regarding the magnitude and direction of Composite Confirmed Interchange is necessary to ensure that each balancing Authority is controlling their generation for the proper amount of Interchange. If the values are not agreed to, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite

VRF and VSL Justifications – INT-009-2, R1	
	Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, excluding Dynamic Schedules and including any interchange as directed by a Reliability Coordinator per INT-010-2 not yet captured in the Composite Confirmed Interchange, for that hour.

VRF and VSL Justifications – INT-009-2, R2	
Proposed VRF	Medium
NERC VRF Discussion	Agreement between Balancing Authorities regarding the source to be used for a Pseudo-Tie is necessary to ensure that each balancing Authority is controlling their generation for the proper amount of Interchange associated with the Pseudo-Tie. If the values are not agreed to, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual (NI_A) term of their respective control ACE (or alternate control process).
FERC VSL G1 Violation Severity Level Assignments Should Not	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-009-2, R2	
Have the Unintended Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process).

VRF and VSL Justifications – INT-009-2, R3	
Proposed VRF	Medium
NERC VRF Discussion	Coordination of Interchange across HVDC is necessary to ensure that the Facility is operated within its limits and that each Balancing Authority is controlling to a correct Interchange value. If the interchange is not appropriately accounted for, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-009-2, R3	
the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie..

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VRF and VSL Justifications for INT-010-2

VRF and VSL Justifications – INT-010-2, R1	
Proposed VRF	Lower
NERC VRF Discussion	After the fact submittal of a Request For Interchange (RFI) will not impact transmission congestion but may impact the ability to adequately assess transmission conditions for future hours. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-010-1, R1, which deals with submitting Arranged Interchange after the fact, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
Proposed Moderate VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for

VRF and VSL Justifications – INT-010-2, R1	
	Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
Proposed High VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
Proposed Severe VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for this requirement mirror existing VSLs for this revised requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single	Guideline 2a: Not applicable. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.

VRF and VSL Justifications – INT-010-2, R1	
Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to ensure that the Request for Interchange was submitted, or for an RFI that was submitted with a start time more than 60 minutes following the resource loss.

VRF and VSL Justifications – INT-010-2, R2	
Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures that modified RFI is submitted for any Interchange that was modified at the direction of a Reliability Coordinator. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.

VRF and VSL Justifications – INT-010-2, R2	
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-010-1, R2, which deals with submitting a modified Arrange Interchange, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.

VRF and VSL Justifications – INT-010-2, R2	
Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of ensuring that a Reliability Adjustment Arranged Interchange reflecting the modification was submitted within 60 minutes following the start of the modification.

VRF and VSL Justifications – INT-010-2, R3	
Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures that modified RFI is submitted for any Interchange that was modified at the direction of a Reliability Coordinator. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-010-1, R3, which deals with submitting a modified Arrange Interchange, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.

VRF and VSL Justifications – INT-010-2, R3	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority did not ensure that a Request for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that scheduled Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned “Severe.” Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-010-2, R3	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of not ensuring that a RFI was submitted within 60 minutes following the start of the scheduled Interchange.

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VRF and VSL Justifications for INT-011-1

The drafting team will complete the following table, providing of analysis and justification for each VRF and VSL, for each requirement in INT-011-1—Intra-Balancing Authority Transaction Identification

VRF and VSL Justifications – INT-011-1, R1	
Proposed VRF	Lower
NERC VRF Discussion	Transfers within a Balancing Authority Area can potentially impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring that Arranged Interchange is submitted. This requirement is assigned a Lower VRF
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A

VRF and VSL Justifications – INT-011-1, R1	
Proposed Severe VSL	The Load-Serving Entity used Point to Point Transmission Service for an intra-Balancing Authority Area transfer, and did not submit a Request for Interchange for an intra-Balancing Authority transfer that is not included in congestion management procedure(s) via an alternate method.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted or the transfer is not included in congestion management procedure(s) via an alternate method.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	The VSL is assigned for a single instance of failing to submit a Request for Interchange or include the transfer in congestion management procedure(s) via an alternate method.

VRF and VSL Justifications – INT-011-1, R1	
on A Single Violation, Not on A Cumulative Number of Violations	

Exhibit H

Summary of Development History and Complete Record of Development

EXHIBIT H

Summary of Development History

The development record for the proposed revisions to Coordinate Interchange Standards is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in **Exhibit I**.

II. Standard Development History

A. Standard Authorization Request Development

The Standard Authorization Request ("SAR") for Phase 1 of Project 2008-12 Coordinate Interchange Standards was submitted on May 27, 2008, as a request for a revision to existing Standards INT-001-2, INT-003-2, INT-004-1, INT-005-2, INT-006-2, INT-007-1, INT-008-2, INT-009-1 and INT-010-1. The initial draft of the Phase 1 SAR was posted from July 2, 2008, to July 31, 2008, for a 30-day public comment period. Stakeholders were asked to provide feedback on the scope of the proposed Phase 1 project as well as specific suggestions for existing sources of data or technical input to support revisions. The final SAR for Phase 1 was modified on December 1, 2008.

B. The First Posting – Informal Comment Period

The first draft of the proposed Phase 1 Coordinate Interchange standards was posted for a 30-day comment period from November 10, 2009, to December 11, 2009. The draft included

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[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2006).

Standards INT-004-3, INT-006-4, INT-009-2, INT-010-2, INT-011-1 and Standards Proposed for Retirement (INT-001-3, INT-003-2, INT-005-3, INT-007-1, INT-008-3). Several documents were posted for guidance with the first draft, including information on issues related to the INT Standards. The NERC Standards Committee placed the proposed project on hold before the responses to this set of comments could be posted. Once the drafting team resumed work on the project, the decision was made to post the proposed standards a second time with the intention of vetting them against the Paragraph 81 criteria.[2]

C. The Second Posting – Informal Comment Period

Second drafts of the proposed Phase 1 Standards were posted for a 30-day comment period from July 25, 2013, to August 23, 2013, to be vetted against the Paragraph 81 criteria. Several documents were posted for guidance with the drafts, including the Unofficial Comment Form; Paragraph 81 Criteria; Stakeholder P81 Comments on INT Standards; a Mapping Document; a Summary of Changes to INT Standards Since Last Posting; and the Standards Proposed for Retirement. There were 29 sets of responses on the drafts, with comments from approximately 68 companies representing 7 of the 10 industry segments. In response to comments and the Independent Expert Review Panel recommendations,[3] the standard drafting team made several changes to the draft standards, including:

INT-004:

- R1: Added an exception for Pseudo-ties that are already accounted for in congestion management tools and eliminated the detail on the MW amount to be included on the transaction;
- R2: Revised to apply to only those LSEs that submitted and RFI per R1, also simplified the language of R2.1, R2.2 and R2.3;

[2] "Paragraph 81" refers to Project 2013-02 which developed criteria for modifying or retiring requirements in NERC Reliability Standards. *See Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61,147 (2013).

[3] *Available at*: http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf.

- R3: Removed as an interim registration process;
- R4: Modified to require entities to register Pseudo-ties when the registration process is available in the NAESB Electric Industry Registry (EIR);
- Added general considerations for curtailment of dynamic transactions to the Guidelines and Technical Basis section of the standard

INT-006:

- R1: Removed the requirement;
- R2, R3: Revised the language for clarity;
- R4: Added the specific entities to perform the review;
- Tables: Removed columns A and C details

INT-009:

- R1: Added phrase "by a Reliability Coordinator" to clarify what aspect of INT-010 is applicable to R1;
- R2: Added language to the Rationale

INT-010:

- R1: Modified language to be consistent with the currently effective requirement;
- R2, R3: Revised the term "created" to "submitted";
- R4: Removed the requirement;
- R5: Removed the requirement;
- R6: Added Pseudo-ties to the requirement and clarified the language;
- Added general considerations for curtailment of dynamic transactions to the Guidelines and Technical Basis section of the standard

D. The Third Posting – Formal Comment Period, Ballots and Non-Binding Polls

Third drafts of the proposed Phase 1 Standards were posted along with nine revised definitions, four new Definitions and the Implementation Plan. A number of supporting documents were posted for guidance with the drafts, including the Unofficial Comment Form; a Mapping Document; the Phase 1 SAR; Violation Risk Factors ("VRF") and Violation Severity Levels ("VSL") Justifications for INT-004-3, INT-006-4, INT-009-2, INT-010-2 and INT-011-1; and Enforceable INT Standards INT-001-2, INT-003-2, INT-004-1, INT-005-2, INT-006-2, INT-007-1, INT-008-2, INT-009-1 and INT-010-1. The 45-day comment period ran from September 30, 2013, to November 13, 2013, and included six individual ballots (one for each of the five Coordinate Interchange Standards and one for the implementation plan and definitions) and five individual non-binding polls (one for each standard's associated VRFs and VSLs).

The ballots for the five Coordinate Interchange Standards ran from November 4, 2013, to November 13, 2013. The ballot for INT-004-3 achieved a 76.12% quorum, and an approval of 67.35%. The ballot for INT-006-4 achieved a 75.82% quorum, and an approval of 75.58%. The ballot for INT-009-2 achieved a 75.82% quorum, and an approval of 68.40%. The ballot for INT-010-2 achieved a 75.82% quorum, and an approval of 58.03%. Lastly, the ballot for INT-011-1 achieved a 75.52% quorum, and an approval of 71.35%. Standards INT-004-3, INT-006-4, INT-009-2 and INT-011-1 received sufficient affirmative votes for approval. Although INT-004-3 received 67.35% approval in the ballot the standard drafting team was persuaded by stakeholder comments to make further improvements to the standard.

The non-binding polls ran from November 4, 2013, to November 14, 2013. The poll for INT-004-3 achieved a 76.80% quorum, and supportive opinions of 70.06%. The poll for INT-006-4 achieved a 76.80% quorum, and supportive opinions of 70.51%. The poll for INT-009-2 achieved a 77.45% quorum, and supportive opinions of 72.00%. The poll for INT-010-2 achieved a 77.45% quorum, and supportive opinions of 63.33%. Lastly, the poll for INT-011-1 achieved a 76.47% quorum, and supportive opinions of 76.25%.

The ballot for the implementation plan and definitions ran from November 4, 2013, to November 15, 2013. The ballot achieved a 76.42% quorum, and an approval of 77.82%.

The standard drafting team received 40 sets of comments from approximately 125 different people from approximately 89 companies representing 9 of the 10 industry segments. In response to comments the standard drafting team made changes to INT-004-3, INT-010-2, the Implementation Plan and two of the Definitions, including:

INT-004-3:

- Changed the definitions of Request for Interchange ("RFI") and Arranged Interchange to enhance clarity;

- Changed “Load-Serving Entity” to “Purchasing-Selling Entity” in the Applicability and Compliance sections and in R1 and R2;
- Changed to the Background section to reflect changes to the standards;
- Added language in the R1 Rationale section to clarify that if no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount;
- Added language in the R2 Rational section to clarify that R2 does not preclude tags from being updated at any time, and that the requirement specifies conditions under which the tag must be updated;
- Changed R3 to clarify Balancing Authority obligations with respect to Pseudo-ties included in the NAESB Electric Industry Registry publication;
- Modified the VSLs for R1, R2 and R3 to ensure that the language is consistent with the language in the requirements;
- Made minor changes to the definition of Sink Balancing Authority, Attaining Balancing Authority, Native Balancing Authority, and to the Background section and the R3 Rationale box for consistency or to correct typographical errors;
- Made various errata changes to ensure that capitalization of glossary terms and acronym usage is consistent across the standard.

INT-010-2:

- Added language and a Rationale box to R1 to provide clarity around “energy sharing agreement”;
- Deleted R4;
- Corrected minor typographical and consistency errors in the Applicability Section, R1, R2, M2 and M3;
- Modified the VSLs in R1 and R2 to ensure that the language is consistent with the language in the requirement;
- Made various errata changes to ensure that capitalization of glossary terms and acronym usage is consistent across the standard.

E. Fourth Posting – Formal Comment Period, Additional Ballots and Additional Non-Binding Polls for INT-004-3, INT-010-2 and Definitions for “Request for Interchange” and “Arranged Interchange”

The fourth drafts of Standards INT-004-3 and INT-010-2 were posted with the revised Definitions for “Request for Interchange” and “Arranged Interchange,” the Implementation Plan and a number of supporting documents, including the Unofficial Comment Form, a Mapping Document, the Phase 1 SAR, the VRF and VSL Justifications for INT-004-3 and INT-010-2, and Enforceable INT Standards INT-004-2 and INT-010-1. The 45-day comment period ran from December 9, 2013, to January 22, 2014, and included additional ballots and non-binding polls from January 10, 2014, to January 22, 2014. There were 24 sets of comments, including comments from approximately 57 companies representing 9 of the 10 Industry Segments. In response to comments, the standard drafting team made changes to INT-004-3, INT-010-2,

INT-004-3:

- Capitalized "Dynamic Transfer" throughout for consistency;
- Added a footnote to "on-time" in Requirement R1 to point to the timing tables in INT-006-4;
- Replaced "For" with "for" in Requirement R2 (Request for Interchange);
- Removed the "," at the end of the Severe VSL for R1 and replaced it with a"."
- Capitalized Frequency Bias, Frequency Bias Setting in the table in the Guidelines and Technical Basis section;
- Reworded two sentences in the Guidelines and Technical Basis section for clarity

INT-010-2:

- Added the Guidelines and Technical Basis Section to the clean version of the standard (it was in the redline version but inadvertently omitted);
- Revised "RFI" to "Request for Interchange" for consistency throughout;
- Added "when the use of the energy sharing agreement exceeded 60 minutes." to the VSLs for R1 to clarify that an RFI does not need to be submitted unless this condition is met;
- Capitalized "Dynamic Transfer" throughout for consistency;
- Reworded two sentences in the Guidelines and Technical Basis section for clarity;
- Removed Transmission Service Provider from section 1.2, Evidence Retention;
- Added "(CEA)" after "Compliance Enforcement Authority" in section 1.2, Evidence Retention;
- Capitalized "Schedule" in the term "Interchange Schedule".

F. Fifth Posting – Final Ballot for INT-006-4, INT-009-2, INT-011-1 and 11 Definitions

The fourth drafts of Standards INT-006-4, INT-009-2 and INT-011-1 were posted with the draft Definitions (excluding the terms "Request for Interchange" and "Arranged Interchange"), the Implementation Plan and a number of supporting documents, including a Mapping Document; the Phase 1 SAR; the VRF and VSL Justifications for INT-006-4, INT-009-2 and INT-011-1; the Consideration of Issues and Directives; the White Paper on Approach to

Addressing Directive in P 866 of Order No. 693; and Enforceable INT Standards INT-006-3 and INT-009-1. The final ballot was conducted from December 10, 2013, to December 20, 2013.

All of the Reliability Standards and Definitions achieved a quorum and sufficient affirmative votes for approval. INT-006-4 achieved a 85.07% quorum, and an approval of 80.77%. INT-009-2 achieved a 85.07% quorum, and an approval of 72.86%. INT-011-1 achieved a 84.78% quorum, and an approval of 72.91%. Lastly, the Definitions achieved a 85.37% quorum, and an approval of 83.60%.

G. Sixth Posting – Additional Ballot for Definitions of "Request for Interchange" and "Arranged Interchange"

An additional ballot of the Definitions of "Request for Interchange" and Arranged Interchange" was conducted from January 16, 2014 through January 29, 2014. The Definitions achieved a quorum of 76.12% and an approval of 92.17%.

H. Seventh Posting –Final Ballot for INT-004-3 and INT-010-2

A final ballot for INT-004-3 and INT-010-2 was conducted from January 27, 2014 through February 5, 2014. INT-004-3 achieved a quorum of 83.88% and an approval of 83.44%. INT-010-2 achieved a quorum of 83.58% and an approval of 91.51%.

I. Eighth Posting – Final Ballot for Definitions of "Request for Interchange" and "Arranged Interchange"

A final ballot of the Definitions of "Request for Interchange" and Arranged Interchange" was conducted from January 31, 2014 through February 10, 2014. The Definitions achieved a quorum of 81.79% and an approval of 90.12%.

J. Board of Trustees Approval

The proposed Definitions and Reliability Standards were approved by the NERC Board of Trustees on February 6, 2014.

Project 2008-12 Coordinate Interchange Standards

Related Files

Status:
INT-004-3, INT-006-4, INT-009-2, INT-010-2 and INT-011-1 were adopted by the NERC Board of Trustees at its February 2014 meeting.

Purpose/Industry Need:
There is confusion regarding the Interchange Authority "function." The need for improved clarity became apparent when entities were recently asked to register in the Compliance Registry as "Interchange Authorities" and entities had difficulty determining which entities were performing the Interchange Authority tasks identified in the set of Coordinate Interchange standards. The Interchange Authority activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities.

The Coordinate Interchange standards dealing with the Interchange Authority and the current Functional Model representations of the Interchange Authority do not reflect technological advances made since the Functional Model working group originally defined the Interchange Authority and advances made since the Coordinate Interchange standards were written.

The modifications in the set of Coordinate Interchange Standards should address the following:

- Determine if the activities in the Coordinate Interchange standards correctly identify the responsible entity.
- Consider requiring the Sink Balancing Authority responsibility for Interchange Authority functions, using an interchange transaction tool process as defined in the latest approved version of the e-Tag Specifications.
- The existing requirements are tool-neutral? consider adding specific references to the e-Tagging process in the requirements
- Consider adding a requirement to have backup capability for use when the interchange transaction tool fails.
- Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to follow.
- Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factors Drafting Team.
- Determine if there is industry-wide support for the Interchange Subcommittee's Principles and definition supporting dynamic transfers and pseudo-ties, and if there is support, modify the requirements and add definitions accordingly.

Draft	Action	Dates	Results	Consideration of Comments
Standards (clean) INT-004-3 (156) INT-006-4 (157) INT-009-2 (158) INT-010-2 (159) INT-011-1 (160)	Final Documents for Board Adoption			

Implementation Plan (161) **Definitions** Clean (162) µ wŜŘťŷŜ óMTMú **VRF and VSL Justifications** INT-004-3 (163) INT-006-4 (164) INT-009-2 (165) INT-010-2 (166) INT-011-1 (167) **Supporting Documents** Mapping Document (168) Consideration of Issues and Directives (169) Analysis of Impacts of Definitions (170)				
Draft 5 **INT-004-3** Clean (140) | Redline to Last Posted (141) VRF/VSL Justification Clean (142) | Redline to Last Posted (143) INT-010-2	Final Ballots Updated Info (149) Info (150) Vote>>	INT-004-3 and INT-010-2 01/27/14 - 02/05/14	Summary(151) Ballot Results: INT-004-3(152) INT-010-2(153)	
		Two Definitions 01/31/14 - 02/10/14	Summary (154) Ballot Results (155)	

Clean (144) | Redline to Last Posted (145) VRF/VSL Justification Clean (146) | Redline to Last Posted (147) Two Definitions Clean (148)				
DRAFT 4 INT-006-4 Clean (116) | Redline to Last Posted (117) INT-009-2 Clean (118) | Redline to Last Posted (119) INT-011-1 Clean (120) (No Changes from Last Posted) Definitions Clean (121) | Redline (122) Implementation Plan Clean (123) | Redline to Last Posted (124) **Supporting Documents** Mapping Document (125) SAR (126)	**Final Ballots** Info (134) Vote>>	12/10/13 - 12/20/13 (closed)	Summary (135) **Ballot Results:** INT-006-4 (136) INT-009-2 (137) INT-011-1 (138) Definitions (139)	

VRF and VSL Justifications: INT-006-4 (127) INT-009-2 (128) INT-011-1 (129) Consideration of Issues and Directives (130) White Paper on Approach to Addressing Directive in P866 of Order No. 693 (131) Enforceable INT Standards: INT-006-3 (132) INT-009-1 (133)				
DRAFT 4 INT-004-3 Clean (89)| Redline to Last Posted (90) INT-010-2 Clean (91) | Redline to Last Posted (92) Definitions Clean (93) | Redline (94) Implementation Plan Clean (95)| Redline to Last Posted (96)	Additional Ballots and Non-Binding Polls Updated Info (104) Info (105) Vote>>	Definitions: 01/16/14 - 01/29/14 (Extended an additional day)	Summary (107) Ballot Results (108)	Consideration of Comments (115)
		Additional Ballots and Non-Binding Polls: 01/10/14 - 01/24/14 (Non-Binding Polls open an additional day) (closed)	Summary (109) Ballot Results: INT-004-3 (110) INT-010-2 (111) **Non-Binding Poll Results:** INT-004-3 (112) INT-010-2 (113)	

Supporting Materials: Unofficial Comment Form (Word) (97) Mapping Document (98) SAR (99) **VRF and VSL Justifications:** INT-004-3 (100) INT-010-2 (101) Enforceable INT Standards: INT-004-2 (102) INT-010-1 (103)	Comment Period Info (106) Submit Comments>>	12/09/13 - 01/22/14 (closed)	Comments Received (114)	
INT-004-3 Clean (44)| Redline to last posted (45)	Join Ballot Pools>>	09/30/13 - 10/29/13 (closed)		
INT-006-4 Clean (46)| Redline to last posted (47) INT-009-2 Clean (48) | Redline to last posted (49) INT-010-2 Clean (50) | Redline to last posted (51) INT-011-1 Clean (52)|	Ballots and Non-binding Polls Updated Info (72) Info (73) Vote>>	11/04/13 - 11/15/13 Extended an additional day to reach quorum (closed)	Summary (75) **Ballot Results** INT-004-3 (76) INT-006-4 (77) INT-009-2 (78) INT-010-2 (79) INT-011-1 (80) Definition (81) **Non-Binding Poll Results:**	Consideration of Comments (88)

Redline to last posted (53) Implementation Plan (54) **Supporting Documents** Unofficial Comment Form (Word) (55) Mapping Document (56) SAR (57) **VRF and VSL Justifications** INT-004-3 (58) INT-006-4 (59) INT-009-2 (60) INT-010-2 (61) INT-011-1 (62) **Enforceable INT Standards** INT-001-3 (63) INT-003-3 (64) INT-004-2 (65) INT-005-3 (66) INT-006-3 (67) INT-007-1 (68) INT-008-3 (69) INT-009-1 (70) INT-010-1 (71)			INT-004-3 (82) INT-006-4 (83) INT-009-2 (84) INT-010-2 (85) INT-011-1 (86)	
	Comment Period Info (74) Submit Comments>>	09/30/13 - 11/15/13 (closed)	Comments Received (87)	
Draft 2 INT-004-3 (26)	Comment Period Info>> (41)	07/25/13 - 08/23/13 (closed)	Comments Received (42)	Consideration of Comments (43)

INT-006-4 (27) INT-009-2 (28) INT-010-2 (29) INT-011-1 (30) **Supporting Documents** Unofficial Comment Form (Word) (31) Paragraph 81 Criteria (32) Stakeholder P81 Comments on INT Standards (33) Mapping Document (34) Summary of Changes to INT Standards Since Last Posting (35) **Standards Proposed for Retirement** INT-001-3 (36) INT-003-3 (37) INT-005-3 (38) INT-007-1 (39) INT-008-3 (40)	Submit Comments>>			
Draft 1	Comment Period Info>> (23)	11/10/2009 - 12/11/2009 (closed)	Comments Received>> (24)	Consideration of Comments>>(25)

Coordinate Interchange Standards INT-004-3 Clean(11) | Redline to last approval (12) INT-006-4 Clean (13) | Redline to last approval (14) INT-009-2 Clean (15) | Redline to Last approval (16) INT-010-2 Clean (17) | Redline to Last Approval (18) INT-011-1 (New Standard) (19) Standards Proposed for Retirement (20) (INT-001-3, INT-003-2, INT-005-3, INT-007-1, INT-008-3) Supporting Materials: Comment Form (Word) (21) Issues Database for INT Standards (22)	Submit Comments>>			

Coordinate Interchange Standard Drafting Team Nominations Supporting Materials: Nomination Form (Word) (9)	Nomination Period Info>>(10) Submit Nomination>>	1/5/2009 - 1/16/2009 (closed)		
Coordinate Interchange Standards Draft SAR Version 2 Clean (7) | Redline to Last Posting (8)				
Coordinate Interchange Standards Draft SAR Version 1 (1) **Supporting Materials:** MISO Letter? IA Registration (2) Comment Form (Word) (3)	Comment Period Info (4) Submit Comments>>	7/2/2008 – 7/31/2008 (closed)	Comments Received>>(5)	Consideration of Comments>>(6)

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard	Modifications to Coordinate Interchange Standards for Applicability and General Upgrade
Request Date	May 27, 2008

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)
Name Interchange Subcommittee	☐	New Standard
Primary Contact Don Lacen, IS Chair	☒	Revision to existing Standards INT-001-2 — Interchange Transaction Tagging INT-003-2 — Interchange Transaction Implementation INT-004-1 — Interchange Transaction Modifications INT-005-2 — Interchange Authority Distributes Arranged Interchange INT-006-2 — Response to Interchange Authority INT-007-1 — Interchange Confirmation INT-008-2 — Interchange Authority Distributes Status INT-009-1 — Implementation of Interchange INT-010-1 — Interchange Coordination Exemptions
Telephone 505-241-2032 Fax 505-241-2582	☐	Withdrawal of existing Standard
E-maildon.lacen@pnm.com	☐	Urgent Action

Purpose **(Describe the proposed standard action: Nomination of a proposed standard, revision to a standard, or withdrawal of a standard and describe what the standard action will achieve.)** Revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange; to address the Interchange Subcommittee's concerns related to the Dynamic Transfers and Pseudo-ties, to address previously identified stakeholder comments and applicable directives from Order 693; and to bring the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and

Enforcement Program.

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.)

There is confusion regarding the Interchange Authority "function". The need for improved clarity became apparent when entities were recently asked to register in the Compliance Registry as "Interchange Authorities" and entities had difficulty determining which entities were performing the Interchange Authority tasks identified in the set of Coordinate Interchange standards. The Interchange Authority activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities.

The Coordinate Interchange standards dealing with the Interchange Authority and the current Functional Model representations of the Interchange Authority do not reflect technological advances made since the Functional Model working group originally defined the Interchange authority and advances made since the Coordinate Interchange standards were written.

There are different interpretations surrounding the requirements associated with Dynamic Transfers and Pseudo-ties. Adding definitions for the terms used to reference Dynamic Transfers and Pseudo-ties (e.g., Dynamic Schedule, Dynamic Transfer, Pseudo-tie) will add clarity to these requirements.

Additional requirements may be needed to address the principles outlined in the Interchange Subcommittee's Principles and Definitions Supporting Dynamic Transfers and Pseudo-ties. (Attachment 2)

The work in this project should be addressed in two phases with a ballot conducted at the end of each phase. The first phase is needed as soon as possible and should focus on the revisions needed to ensure that each requirement is assigned to a user, owner or operator of the bulk power system. All other proposed revisions should be addressed in the second phase of the project.

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

The modifications in the set of Coordinate Interchange Standards should address the following:

- Determine if the activities in the Coordinate Interchange standards correctly identify the responsible entity.
- Consider requiring the Sink Balancing Authority responsibility for Interchange Authority functions, using an interchange transaction tool process as defined in the latest approved version of the e-Tag Specifications.
- The existing requirements are tool-neutral - consider adding specific references to the e-Tagging process in the requirements
- Consider adding a requirement to have backup capability for use when the interchange transaction tool fails.
- Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to

follow.

- Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factor drafting team. (See Attachment 1)
- Determine if there is industry-wide support for the Interchange Subcommittee's Principles and definition supporting dynamic transfers and pseudo-ties, and if there is support, modify the requirements and add definitions accordingly.

Make other changes to the standards to bring them into conformance with the latest version of the Reliability Standards Development Procedure, Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

The work in this project should be done in two phases, with the first phase focused solely on clarifying the applicability of each requirement in the existing set of standards. All other revisions should take place in a second phase.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Revise the following set of Coordinate Interchange Standards so that the responsibility for each of the requirements is clearly assigned to an owner, operator or user of the bulk power system, and not to a tool.

INT-001-2 — Interchange Transaction Tagging
INT-003-2 — Interchange Transaction Implementation
INT-004-1 — Interchange Transaction Modifications
INT-005-2 — Interchange Authority Distributes Arranged Interchange
INT-006-2 — Response to Interchange Authority
INT-007-1 — Interchange Confirmation
INT-008-2 — Interchange Authority Distributes Status
INT-009-1 — Implementation of Interchange
INT-010-1 — Interchange Coordination Exemptions

Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to follow.

Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factor drafting team. (See Attachment 1)

Address the principles and definitions proposed by the Interchange Subcommittee in support of dynamic transfers and pseudo-ties. (See Attachment 2)

Make other changes to the standards to bring them into conformance with the latest version of the Reliability Standards Development Procedure, Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

The work in this project should be addressed in two phases with a ballot conducted at the end of each phase. The first phase is needed as soon as possible and should focus on the revisions needed to ensure that each requirement is assigned to a user, owner or operator of the bulk power system. All other proposed revisions should be addressed in the second phase of the project.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	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 a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	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.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	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

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1

(Issues originally intended for Project 2009-03 – Interchange Information)

INT-001-2 Interchange Information

Directives from FERC Order 693

- Include a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and “non-Order No. 888” transfers.
- Consider Santa Clara’s comments about the applicability of the LSE in the standard as part of the standards development process.

V0 Industry Comments

- R1 - Too stringent
- R1 – Who tags dynamic schedules?
- Load PSE responsibility is new restriction
- Clarify tagging of reserves
- R2.2 – 60 minute time frame questioned
- Question on generation scheduling
- Onerous to BA’s
- More commercial problem than reliability
- Lack of compliance

VRF Comments

- R1, 1.1, 2, 2.1, 2.2 – commercial and administrative

INT-003-2 Interchange Transaction Implementation

Unresolved Directives from FERC Order 693 – none

VRF Comments

- R1, 1.1, 1.1.2, 1.2 – commercial and administrative

INT-004-1 Dynamic Interchange Transaction Modifications

Unresolved Directives from FERC Order 693 – none

V0 Industry Comments

- Replace TSP with TOP
- Need to address tag curtailment
- Suggested non-compliance levels
- Non-compliance based on %
- Use WECC criteria

VRF Comments

- R2, 2.2, 2.3 – commercial and administrative

INT-005-2 Interchange Authority Distributes Arranged Interchange

Unresolved Directives from FERC Order 693 – none

VRF Comment

- R5 – administrative

INT-006-2 Response to Interchange Authority

Directives from FERC Order 693

- Include reliability coordinators and transmission operators as applicable entities.
- Require reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities' necessary transaction modifications before implementation.
- Consider the suggestions made by EEI and TVA and address questions raised by Entergy and Northern Indiana as part of the standard development process.

INT-007-1 Interchange Confirmation

Unresolved Directives from FERC Order 693 – none

VRF Comment

- R1, 1.1, 1.3, 1.3.1, 1.3.2, 1.3.3, 1.3.4, 1.4 – administrative

INT-008-2 Interchange Authority Distributes Status

Directives from FERC Order 693

- Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

VRF Comments

- R1.1.1 & 1.1.2 – commercial and administrative

INT-009-1 Implementation of Interchange

Directives from FERC Order 693

- Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

INT-010-1 Interchange Coordination Exemptions

Directives from FERC Order 693

- Consider Northern Indiana's and ISO-NE's suggestions in the standards development process.

VRF Comments

- R1 & 3 – administrative

Attachment 2 – Interchange Subcommittee's Principles and Definitions for Dynamic Schedules and Pseudo-ties

Dynamic Schedules

A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between balancing areas. A dynamic schedule must not change a balancing area's jurisdiction; that is, the native balancing area continues to exercise operational jurisdiction over, and provides basic balancing area services to, the dynamically scheduled resources.

All dynamic schedules used to assign the control of generation, loads, or resources from one balancing area to another must meet the following requirements:

1. Telemetry

1.1. Appropriate telemetry for a dynamic schedule must be in place and incorporated by all affected balancing areas. Standards requirements associated with this should address appropriateness issues related to accuracy, sampling rate, etc. which would impact reliability. For example, the relationship of BAL-005-1 R10 and BAL-005-1, R16 should be confirmed.

2. Transmission Service

2.1. Prior to implementation of the dynamic schedule of load or generation, it is the obligation of each involved balancing area to ensure that the dynamic schedule is implemented such that the tariff requirements of the applicable transmission provider(s) are met, including applicable ancillary services and provision of losses.

2.2. If transmission service between the source and sink balancing areas is curtailed then the allowable range of the magnitude of the schedules between them, including dynamic schedules, must be curtailed accordingly. Since dynamic schedules are implemented in ACE via telemetry, curtailment of e-Tags associated with dynamic schedules must be complemented with appropriate adjustments to the telemetered values used in ACE to make the curtailment be physically implemented via ACE control action.

3. System Modeling

3.1. Each balancing area must ensure that the dynamic transfer of load or generation through a dynamic schedule is coordinated with the Reliability Coordinator(s) with responsibility over the native, attaining, and contract intermediary balancing areas so that the dynamic schedule can be properly implemented in the system modeling of the affected generation or load, and necessary data provision requirements are met. Coordination must include tagging of the resultant scheduled interchange for use by other transmission providers and balancing areas for system security analysis and calculation of ATC.

3.2. When a dynamic schedule is used to serve load within another balancing area, the balancing area where the load is electrically connected (native balancing area) must include that load in its balancing area load forecast and any subsequent reporting as needed. This is necessary because the system models must adequately capture the projected demand on the system (load forecast), and the projected supply (provided by the electronic tagging system).

4. Dynamic Schedule Coordination and Scheduling

4.1. Although implemented in the ACE via telemetry, implementation of a dynamic schedule for NERC-identified reliability analysis services must be through the use of an interchange transaction between balancing areas. As such, all dynamic schedules must be tagged and implemented in accordance with NERC Standards.

4.2. Energy exchanged between the source, sink, and intermediary balancing areas as a dynamic schedule is the metered or calculated (obtained by the integration of the dynamic schedule signal over the operating hour) energy for the loads and/or resources for the hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.
4.3. The native balancing area must ensure that agreements are in place defining the responsibility for providing applicable ancillary/interconnected operations services.
4.4. The drafting team should consider reliability impacts and draft appropriate standards related to how dynamic schedules are modeled from various perspectives such as level of detail (i.e. degree to which composite representation is allowed such as each generator having dynamic schedule or allowing a composite plant dynamic schedule) and use of block schedules to serve part of a dynamic schedule. In the latter case, although a single telemetered value may be used in the ACE for a load, it can be represented in the e-Tagging by a combination of one or more block schedules for part of the load and a dynamic schedule for the remainder to represent the dynamic nature of a load.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the dynamic schedule on a plan for how the balancing areas will operate during a loss of the dynamic schedule telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.
5.2. The native balancing area, attaining balancing area and intermediary balancing areas shall agree before implementation of the dynamic schedule upon a plan for how the load will be served during abnormal system conditions including periods of time when the transfer path between them is unavailable. The native balancing area, attaining control area and intermediary balancing areas shall also agree before implementation of the dynamic schedule as to how the generation serving the dynamic schedule will respond during abnormal system conditions, including periods of time when the transfer path between them is unavailable.

Pseudo-Ties
Pseudo-ties are often employed to assign generators, loads, or both from the balancing area to which they are physically connected into a balancing area that has effective operational control of them. Thus, pseudo-ties provide for change of balancing area jurisdiction from the native to the attaining balancing area and at the same time make the attaining balancing area provider of balancing area services. This methodology is also referred to as “AGC Interchange” or “Non-Contiguous Pool Tie.” In practice, pseudo-ties may be implemented based upon metered or calculated values. All balancing areas involved account for the power exchange and associated transmission losses as actual interchange between the balancing areas, both in their ACE equations and throughout all of their energy accounting processes.

All pseudo-ties used to assign generation, loads, or resources from the native balancing area to the attaining balancing area must meet the following requirements:
1. Telemetry
1.1. Appropriate telemetry must be in place and incorporated by all affected balancing areas.

2. Transmission Service
2.1. Prior to implementation of the dynamic transfer of load or generation by pseudo-tie, each involved balancing area shall ensure that the pseudo-tie is implemented such that the

tariff requirements of the applicable transmission provider(s), including applicable ancillary services and provision of losses, are met.
2.2. If transmission service between the native and attaining balancing areas is curtailed, then the allowable range of the magnitude of the pseudo-ties between them must be limited accordingly to these constraints. Since pseudo-ties are implemented in ACE via telemetry, appropriate adjustments must be made to the telemetered values used in ACE to make a curtailment be physically implemented via ACE control action.
2.3. Pseudo-ties must be implemented on firm transmission and are subject to curtailment on a pro rata basis with other firm transactions.

3. System Modeling
3.1. The assignment of load or generation into the control response of another balancing area must be appropriately captured in the IDC and security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators. It is the obligation of each balancing area to ensure that the dynamic transfer of load or generation by pseudo-ties is coordinated with the Reliability Coordinator(s) that have responsibility over the native, attaining, and contract intermediary balancing areas so that the pseudo-tie can be properly implemented in the system modeling of the generation or load affected, and necessary data provision requirements are met.
3.2. The attaining balancing area dynamically transferring load into its effective boundaries through a pseudo-tie shall ensure that load forecasts and subsequent balancing area reporting reflect the load incorporated within its balancing area boundaries.
3.3. If the reliability impact of the pseudo-tie cannot be accurately captured in the IDC and the security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators, the parties must implement the dynamic transfer either through use of a dynamic schedule, or through a combined implementation of pseudo-tie and dynamic schedule where the load or generation within the native balancing area is separately modeled in the IDC.
3.4. The drafting team should consider clarifying how pseudo-tie can be used in reliability analysis activities. For example, since they are not physical ties, should they be omitted from being used as part of a defined flowgate and in physical interface calculations yet be included in inadvertent calculations

4. Pseudo-Ties Coordination and Scheduling
4.1. Subsequent to moving load or resources into an attaining balancing area through pseudo-ties, all interchange transactions or other energy transfers to the loads or from the resources must be coordinated by the attaining balancing area.
4.2. The attaining balancing area assumes responsibility for balancing area services required by the assigned loads and/or resources. The attaining balancing area assumes all regulation, contingency reserves, and other balancing area responsibilities for the loads and/or resources in question.
4.3. Energy exchanged between the native and attaining balancing areas by the pseudo-tie method is accounted for by the associated revenue meter reading for the operating hour (if such meter exists at the dynamically assigned resource or load) or energy calculated by integrating the associated telemetered real-time signal over the operating hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie on a plan for how the balancing areas will operate during a loss of the pseudo-tie telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good

value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

5.2. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie upon a plan for how the load will be served during abnormal system conditions including periods of time when the interconnection between them is lost. The native balancing area, attaining balancing area, and intermediary balancing areas shall also agree before implementation of the pseudo-tie how the entities will respond during abnormal system conditions, including periods of time when the connection between them is unavailable.

Dynamic Transfer Reference Document

The Drafting Team should take the existing Dynamic Transfer Reference Document, update it as necessary to reflect Functional Model terms and any changes necessary as a result of new requirements from the standards drafting resulting from this SAR and submit it for ballot as a formal reference document linked to those standards. This will provide the industry with a formal, official document to provide guidance on the implementation of dynamic transfers covered in the standards.

The Interchange Subcommittee recommends moving INT-001 standard requirement R.1. to a more appropriate INT standard such as INT-001 or INT-003.

Note: In addition to the above requirements, the NERC Glossary of Terms may need to be amended to include the following new or revised definitions:

ATTAINING BALANCING AREA — A balancing area bringing generation or load into its effective control boundaries through dynamic transfer from the Native Balancing area.

DYNAMIC SCHEDULE — A telemetered reading, or value that is updated in real-time and used as a schedule in the AGC/ACE equation of the affected balancing areas and the integration of which is treated as a schedule for interchange accounting purposes. To the extent that no associated energy metering equipment exists, the integration of the telemetered real time signal is used as a scheduled MWh value for interchange accounting purposes.

DYNAMIC TRANSFER — The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to implement a dynamic schedule or pseudo-tie.

INTEGRATION in the context of dynamic schedules and pseudo-ties means the value could be mathematically calculated or determined mechanically with a metering device.

INTERCONNECTED OPERATIONS SERVICE (IOS) — A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected bulk electric systems.

NATIVE BALANCING AREA — A balancing area from which a portion of its physically interconnected generation and/or load is assigned from its effective control boundaries through dynamic transfer to the attaining balancing area.

PSEUDO-TIE — A telemetered reading, or value that is updated in real time, representative of generation or load assigned dynamically between balancing areas and used as a tie line flow in the affected balancing areas' AGC/ACE equation, but for which no physical balancing area tie actually exists. To the extent that no associated energy metering equipment exists,

the integration of the telemetered real time signal is used as a metered MWh value for interchange accounting purposes.

Ameren Services

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April 25, 2008

Mr. Rick Sergel, President
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116-390 Village Boulevard
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Mr. Gerry Cauley, President
SERC Reliability Corporation
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Mr. Dan Skaar, President
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2774 Cleveland Avenue, North
Roseville, Minnesota 55113-1127

Mr. Timothy R. Gallagher, President
Reliability*First* Corporation
320 Springside Drive, Suite 300
Akron, Ohio 44333-4542

Re: Interchange Authority Registration

Dear Sirs:

The Balancing Authorities[1] in the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") and the Midwest ISO submit this letter to express their concerns related to registration for the Interchange Authority function. As discussed below, without further clarification, at this time neither the Midwest ISO nor its Balancing Authorities believe they should register as an Interchange Authority.

An Interchange Authority is defined as "[t]he responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes."[2]

The North American Electric Reliability Corporation ("NERC") has added Interchange Authority to the list of functional entities that are required to be included on the NERC Compliance Registry Criteria ("NRC") (Revision 4.0). NERC delegated the responsibility to the Regional Entities for identifying the organization to be registered in the NRC. Various Balancing Authorities and the Midwest ISO are members of Midwest Reliability Organization ("MRO"), SERC Reliability Corporation ("SERC"), and Reliability*First* Corporation ("RFC"). The MRO has requested that its members register as Interchange Authorities by April 25, 2008, and SERC has also contacted its members about registration.

While the Midwest ISO and its Balancing Authorities do not dispute the need for the industry to determine what entity should register as an Interchange Authority, they have

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1 Alliant Energy; Ameren; City of Springfield, IL; Duke Energy; First Energy; Great River Energy; Madison Gas and Electric Company; Michigan Electric Coordinated System; Minnesota Power, Inc.; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company / Xcel Energy; Otter Tail Power Company; Southern Indiana Gas & Electric Co.; Southern Minnesota Municipal Power Agency; Upper Peninsula Power Co.; Wisconsin Electric Power Co.; Wisconsin Public Service Corporation

2 As defined in the "Glossary of Terms Used in Reliability Standards" in the "Reliability Standards for the Bulk Electric Systems of North America" dated March 26, 2008.

the following concerns about registration at this time. First, there is not a common understanding of the Interchange Authority function in the industry. The conversion of NERC Policy 3 to the Version 0 and subsequent standards, took procedure steps in the e-tag process and created requirements, some of which were assigned to a function called the Interchange Authority, while others were assigned to the Balancing Authority, Purchasing-Selling Entity, Reliability Coordinator and Transmission Service Provider. Throughout the development of the standards there has not been clarity on whether the Interchange Authority function is an entity or a function provided by software.

Second, the requirements in the standards that deal with the Interchange Authority are primarily those tasks done by e-tagging services and not the Midwest ISO or its Balancing Authorities.

Third, the standards and associated requirements assigned to the Balancing Authority were developed, and should continue to be developed, under the Reliability Standard Development Procedure approved by the Federal Energy Regulatory Commission. Throughout the development of the Interchange Scheduling and Coordination ("INT") Standards, the industry comments and subsequent voting on the Standards were based upon the understanding of the requirements applicable to the Balancing Authority. If the intent was to have the Balancing Authority perform the function of the Interchange Authority, or to have the Balancing Authority responsible for ensuring the Interchange Authority function was performed, such requirements should have been stated in the proposed standards to allow the industry to comment through the ANSI-approved NERC process.

Fourth, in its letter to the Regional Entities, NERC provided the following guidance on the registration of Interchange Authorities:

1. If a Balancing Authority performs the Interchange Authority function or is responsible for ensuring the Interchange Authority function is performed, then that Balancing Authority should be registered as an Interchange Authority in the Compliance Registry.
2. Balancing Authorities currently listed in the Compliance Registry should be able to assist in identifying the responsible entity that is performing the Interchange Authority function for their interchange transactions.
3. A software company that develops software that is used as a tool to enable an entity to perform the Interchange Authority function shall not be registered as an Interchange Authority unless the software company is an owner, operator, or user of the bulk power system. The entity that is using the software tool to perform the Interchange Authority function is responsible for compliance with the NERC Reliability Standards applicable to Interchange Authority and shall be registered as the Interchange Authority.

Though the Midwest ISO voluntarily provides the tasks of the Interchange Authority through use of the e-tagging software, it is not required to provide those tasks under the current standards; nor do the Standards require the Balancing Authority to be responsible for ensuring the Interchange Authority function is performed.

Fifth, it is not known what requirements under the Critical Infrastructure Protection Standards would apply, if any, to software being used from a remote vendor. The Midwest ISO and its Balancing Authorities would be interested in NERC interpretation of the applicability, as the voluntary provision of the Interchange Authority function must consider whether the provision justifies the compliance risk assumed for the function.

Finally, under the Enhanced Scheduling Agent Waiver, the Midwest ISO, on behalf of its Balancing Authorities, performs the tasks typically assigned to the Balancing Authority in the INT Standards. In fact, the waiver is listed in the Regional Differences for the INT Standards applicable to the Balancing Authority. As the INT Standards did not include requirements for the Balancing Authorities to assume the responsibilities of the Interchange Authority, or otherwise ensure that the Interchange Authority function is provided, the Midwest ISO and its Balancing Authorities did not request that the Enhanced Scheduling Agent Waiver be included as a Regional Difference for the INT Standards applicable to the Interchange Authority.

In conclusion, the requirements in the Standards for the Interchange Authority appear to point to something other than the Midwest ISO or its Balancing Authorities. As the Midwest ISO and its Balancing Authorities believe that NERC and the industry need to come to an informed decision following the ANSI-approved process, if NERC believes that certain Interchange Authority tasks should default to the Balancing Authority, or the Balancing Authority otherwise should be held responsible for the provision of the Interchange Authority tasks, the Midwest ISO and the Balancing Authorities ask that Standard Authorization Requests be submitted with the necessary changes for industry review.

Sincerely,

Maureen A. Borkowski

Maureen A. Borkowski
Chair, Midwest ISO Balancing Authority Committee

Project 2008-12 calls for the revision of each of the following standards:

INT-001-2 — Interchange Transaction Tagging

INT-003-2 — Interchange Transaction Implementation

INT-004-1 — Interchange Transaction Modifications

INT-005-2 — Interchange Authority Distributes Arranged Interchange

INT-006-2 — Response to Interchange Authority

INT-007-1 — Interchange Confirmation

INT-008-2 — Interchange Authority Distributes Status

INT-009-1 — Implementation of Interchange

The proposed modifications include the following:

Ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange

Address the Interchange Subcommittee's concerns related to the Dynamic Transfers and Pseudo-ties

Address previously identified stakeholder comments and applicable directives from Order 693

Bring the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

Please review the SAR and the letter from the Midwest ISO Balancing Authority Committee regarding the registration of the Interchange Authority function and then answer the following questions. Please complete the form by **July 31, 2008**.

1. Do you agree that there is a reliability-related reason for the proposed standard action?

   ☐ Yes

   ☐ No

   ☐ Yes and No

   Comments:

2. Do you agree with the scope of the proposed standard action?

   ☐ Yes

   ☐ No

   ☐ Yes and No

   Comments:

3. Do you agree with the applicability of the proposed standard action? If not, what functional entities do you think need to be added/deleted?

☐ Yes
☐ No
☐ Yes and No

Comments:

4. If you are aware of any Regional Variances associated with the proposed standard action, please identify them here.

   Comments:

5. If you are aware of the need for a business practice to support the proposed standard action, please identify it here.

   Comments:

6. If you have any other comments on this SAR that you haven't already provided in response to the previous questions, please provide them here.

   Comments:

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Periods Open July 2, 2008

Now available at:
http://www.nerc.com/~filez/standards/Reliability_Standards_Under_Development.html

Comment Period for Project 2007-01 — Underfrequency Load Shedding Posted for 45-day Comment Period

The Underfrequency Load Shedding (UFLS) Standard Drafting Team has posted its initial draft of a set of characteristics for inclusion in regional underfrequency load shedding standards (Underfrequency Load Shedding Regional Reliability Standards Characteristics), along with an implementation plan for a 45-day comment period from July 2 through August 15, 2008.

Please use this electronic comment form to submit comments on the initial draft of the UFLS Regional Reliability Standards Characteristics and associated implementation plan by 8 p.m. (EDT) on **Friday, August 15, 2008.** If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060.

If you need an off-line, unofficial copy of the questions in the comment form, there is a copy of the comment form posted at the following site:

http://www.nerc.com/~filez/standards/Underfrequency_Load_Shedding.html

Comment Period for Project 2008-12 — SAR for Modifications to Coordinate Interchange Standards for Applicability and General Upgrade Opens July 2, 2008

The Standards Committee authorized posting a new SAR that addresses modifications to the set of Coordinate Interchange standards identified below for a 30-day comment period from July 2–31, 2008:

- INT-001-2 — Interchange Transaction Tagging
- INT-003-2 — Interchange Transaction Implementation
- INT-004-1 — Interchange Transaction Modifications
- INT-005-2 — Interchange Authority Distributes Arranged Interchange
- INT-006-2 — Response to Interchange Authority
- INT-007-1 — Interchange Confirmation
- INT-008-2 — Interchange Authority Distributes Status
- INT-009-1 — Implementation of Interchange
- INT-010-1 — Interchange Coordination Exemptions

The proposed modifications would clarify the applicability of the requirements, address issues raised by FERC, stakeholders and the Interchange Subcommittee, and bring the set of standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement program.

Please use this electronic comment form to submit comments on the SAR for modifications to Coordinate Standards and general updates by **July 31, 2008**. If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060.

If you need an off-line, unofficial copy of the questions in the comment form, there is a copy of the comment form posted at the following site:

http://www.nerc.com/~filez/standards/Project2008-12_Coordinate_Interchange_Stds_Modifications.html

Standards Development Process

The *Reliability Standards Development Procedure Manual* 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 Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

Consideration of Comments on SAR to Modify and Update Coordinate Interchange Standards — Project 2008-12

The Coordinate Interchange Standard Drafting Team thanks all commenters who submitted comments on the 1st draft of the SAR to modify and update Coordinate Interchange standards. These standards were posted for a 30-day public comment period from July 2, 2008 through July 31, 2008. The stakeholders were asked to provide feedback on the SAR through a special Electronic Standard Comment Form. There were more than 22 sets of comments, including comments from more than 100 different people from approximately 50 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/~filez/standards/Project2008-12_Coordinate_Interchange_Stds_Modifications.html

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.	Guy Zito	NPCC RSC										x

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Thompson	Consolidated Edison Co. of New York, Inc.	NPCC	1
2.	David Kiguel	Hydro One Networks Inc.	NPCC	1
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Frederick White	Northeast Utilities	NPCC	1
5.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
6.	Ron Falsetti	Independent Electricity System Operator	NPCC	2
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Randy MacDonald	New Brunswick System Operator	NPCC	2
9.	Gregory Campoli	New York Independent System Operator	NPCC	2
10.	Michael Ranalli	National Grid	NPCC	3
11.	Ronald E. Hart	Dominion Resources, Inc.	NPCC	5
12.	Ralph Rufrano	New York Power Authority	NPCC	5
13.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
14.	Michael Gildea	Constellation Energy	NPCC	6
15.	Brian D. Evans-Mongeon	Utility Services	NPCC	6
16.	Donald E. Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
17.	Brian Hogue	NPCC	NPCC	10
18.	Alan Adamson	New York State Reliability Council	NPCC	10
19.	Guy Zito	NPCC	NPCC	10
20.	Lee Pedowicz	NPCC	NPCC	10
21.	Gerry Dunbar	NPCC	NPCC	10

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Thad Ness	American Electric Power	x		x		x	x				
3.	Robert Sullivan	California ISO		x								
4.	Jim S. Griffith	SERC OC Standards Review Group	x		x		x					

Additional Member	Additional Organization	Region	Segment Selection	
1.	Robert Thomasson	Big Rivers Electric Cooperative	SERC	1, 3, 5
2.	Jim Case	Entergy	SERC	1, 3, 5
3.	Raymond Vice	Southern Co.	SERC	1, 3, 5

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

4.	Marc Butts	Southern Co.	SERC	1, 3, 5
5.	J. T. Wood	Southern Co.	SERC	1, 3, 5
6.	Mike Oatts	Southern Co.	SERC	1, 3, 5
7.	Jim Busbin	Southern Co.	SERC	1, 3, 5
8.	Roman Carter	Southern Co.	SERC	1, 3, 5
9.	Carter Edge	SERC Reliability Corp.	SERC	10
10.	John Troha	SERC Reliability Corp.	SERC	10

			1	2	3	4	5	6	7	8	9	10
5.	Jeffery V. Hackman	Ameren	x									
6.	Ron Falsetti	Ontario IESO		x								
7.	Anthony Jankowski	We Energies			x	x	x					
8.	Robert Rhodes	SPP – Operating Reliability Working Group (ORWG)	x	x	x	x	x					

Additional Member		Additional Organization	Region	Segment Selection
1.	John Boshears	City Utilities, Springfield, MO	SPP	1, 3, 5
2.	Brian Berkstresser	Empire District Electric	SPP	1, 3, 5
3.	Bill Bateman	East Texas Electric Coop	SPP	3, 4
4.	Lisa Carter	Southwest Power Pool	SPP	2
5.	Mike Gammon	Kansas City Power & Light	SPP	1, 3, 5
6.	Don Hargrove	Oklahoma Gas & Electric	SPP	1, 3, 5
7.	Danny McDaniel	CLECO	SPP	1, 3, 5
8.	Kyle McMenamin	Southwestern Public Service	SPP	1, 3, 5
9.	Eddy Reece	Rayburn Country Electric Coop	SPP	3, 4
10.	Robert Rhodes	Southwest Power Pool	SPP	2

			1	2	3	4	5	6	7	8	9	10
9.	Joe Knight	Great River Energy	x		x		x	x				
10.	Marie Knox	MRO NERC Standards Review Subcommittee (NSRS)		x								

Additional Member		Additional Organization	Region	Segment Selection
1.	Neal Balu	Wisconsin Public Service	MRO	3, 4, 5, 6
2.	Terry Bilke	Midwest ISO Inc.	MRO	2
3.	Carol Gerou	Minnesota Power	MRO	1, 3, 5, 6
4.	Jim Haigh	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Tom Mielnik	MidAmerican Energy Company	MRO	1, 3, 5, 6
7.	Pam Sordet	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Larry Brusseau	Midwest Reliability Organization	MRO	10
13.	Mike Brytowski	Midwest Reliability Organization	MRO	10

			1	2	3	4	5	6	7	8	9	10
11.	Shane Jenson	Omaha Public Power District	x		x		x				x	
12.	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

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

2.	Kristy Humphrey	Power Scheduling Coordination	WECC	3, 5, 6
3.	Fran Halpin	Generation Support	WECC	3, 5, 6
4.	Bart McManus	Transmission Technical Operations	WECC	1
5.	Troy Simpson	Transmission Bus Process & Implementation	WECC	1
6.	Joel Jenck	Power Scheduling Coordination	WECC	3, 5, 6

			1	2	3	4	5	6	7	8	9	10
13.	Jim Cyrulewski	Functional Model Working Group								x		
14.	Kris Manchur	Manitoba Hydro	x		x		x	x				
15.	Sandra Shaffer	PacifiCorp	x		x		x					
16.	Greg Rowland	Duke Energy Corp.	x		x		x	x				
17.	Eric Grau	Tennessee Valley Authority									x	
18.	Marie Knox	Midwest ISO Stakeholders Standards Collaborators		2								

Additional Member	Additional Organization	Region	Segment Selection	
1.	Nicholas Browning	Midwest ISO	RFC	2
2.	Barb Kedrowski	We Energies	RFC	3, 5
3.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
4.	Joe Dobes	NIPSCO	RFC	1
5.	Roger Huhn	NIPSCO	RFC	6
6.	Bill SeDoris	NIPSCO	RFC	3
7.	Kirit Shah	Ameren	SERC	1
8.	Sam Ciccone	First Energy	RFC	1
9.	Dave Folk	First Energy	RFC	1
10.	Rob Martinko	First Energy	RFC	1
11.	Doug Hohlbaugh	First Energy	RFC	1

			1	2	3	4	5	6	7	8	9	10
19.	Patrick Brown	PJM Interconnection, L.L.C.		x								
20.	Mark W. Hackney	Arizona Public Service Company (AZPS)	x									
21.	Sam Ciccone	FirstEnergy	x	x		x		x				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Doug Hohlbaugh	FE	RFC	1, 3, 5, 6
2.	Dave Folk	FE	RFC	1, 3, 5, 6
3.	Rob Martinko	FE	RFC	1, 3, 5, 6
4.	Larry Hartley	FES	RFC	3

			1	2	3	4	5	6	7	8	9	10
22.	Mark Heimbach	PPL EnergyPlus						x				

Additional Member	Additional Organization	Region	Segment Selection	
1.	John Cummings	PPL EnergyPlus	WECC	6

			1	2	3	4	5	6	7	8	9	10
23.	Steve Ruechert	WECC										x

1. Do you agree that there is a reliability-related reason for the proposed standard action?

Organization	Question 1:	Question 1 Comments:
NPCC	Yes	Regional interchange and improving the clarity of functional responsibilities among entities has a direct impact on reliability.
AEP	Yes	The applicability for the responsible functional reliability entity needs to be more realistic to the actual operating model and include any entities that can impact or compromise the ability to ensure reliability.
CAISO	Yes	
SERC OC Standards Review Group	Yes	
Ameren	Yes	
Independent Electricity System Operator - Ontario	Yes	
We Energies	Yes	Must have clear responsibilities in standards.
Operating Reliability Working Group (ORWG)	Yes	
Great River Energy	No	INT-001-2 - Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" INT-006-2 - TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for ETag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour? INT-008-2 - Yes.
MRO NERC Standards Review Subcommittee (NSRS)		Please note that question 1 is different than the word form provided on the website. The word comment form states, "Do you agree that there is a reliability-related reason for the proposed standard action?" and offers the options of Yes, No, and Yes and No. Our group responded with "Yes and No" and offered the comments listed below:INT-001-2 - Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" INT-006-2 - TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for ETag submissions. What system conditions exist that will give an RC cause to approve or deny a

Organization	Question 1:	Question 1 Comments:
		transaction a month out? a day? an hour?INT-008-2 - Yes.
OPPD	Yes	
Bonneville Power Administration	Yes	
Functional Model Working Group	Yes	
Manitoba Hydro	Yes	
PacifiCorp	Yes	
Duke energy	No	The scope of the SAR appears administrative, and not reliability-related. However we do believe the standards need to be revised to address those items.
Tennessee Valley Authority	Yes	TVA agrees with the comment that referring to e-tag only describes the requirements and technical specifications to implement an electronic transaction information system. It provides a basis for tools designed to facilitate interchange transaction information between two parties. It does not specify "the tool," only what the tool must be capable of doing.INT-001-2: TVA is in favor of including a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers. Although the IDC does not currently use this information, the BAs use it in their forward reliability analysis.
Midwest ISO Stakeholders Standards Collaborators	No	Regarding INT-001-2, no, we do not agree. Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" Regarding INT-006-2, no, we do not agree. TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for E-Tag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour? Regarding INT-008-2, yes, we agree.
PJM Interconnection	No	Regarding the purpose of the SAR as stated in the body of the SAR (i.e. not including FERC directives): The stated purpose of the SAR (the last sentence in the PURPOSE section) is "to revise …INT standards to reflect that the IA functions ARE performed by an automated system rather then an entity." PJM believes that NERC standards are written as mandatory obligations assigned to registered entities that in turn are responsible for performing those tasks and who are subject to non-compliance penalties. Thus the stated purpose (to reflect/assign the IA tasks to an automated system) conflicts with that concept. PJM also believes that NERC Interpretations are used to explain implementation issues. Thus the SAR's stated purpose, as noted above, would fall into this latter category.

Organization	Question 1:	Question 1 Comments:
		PJM agrees that it is appropriate to change and/or revise existing requirements to ensure that each requirement is assigned to an owner or operator of the bulk power system and not to a tool. Thus we agree with the stated justification in that same PURPOSE section, that is, there is a need to "resolve the discrepancy" and the confusion related to the IA Function. But there is not so much a need for a change in the standards as there is for an interpretation of those standards. PJM supports NERC's current standards that identify the reliability need for verifying Interchange transactions and that recognize that group of tasks as a unique functional set of tasks that CAN BE assigned and complied with by an entity that can be (but not necessarily is) an RC, BA, or any other registered entity. Moreover, PJM supports the NERC registration process that in the absence of any one or more entities agreeing to register as an IA, and until one or more entities register as IAs, to register all BAs to be responsible for those tasks assigned in the INT standards to the IA Function. Regarding Attachment 1 to the SAR: Attachment 1 (FERC Order 693) FERC Order 693 under INT-001-2, Interchange Information, directs NERC to "include a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and 'non-Order No. 888' transfers." PJM supports internal Network transactions and does not recognize internal point-to-point transfers within our Balancing Authority area. All previous grandfathered point-to-point transactions have been closed out. While PJM does support the tracking of interchange in, out, or through a balancing authority as necessary, PJM opposes any attempt to redefine Network transactions as point-to-point transactions particularly since Network market flow is already included in TLR cuts, thus this suggestion is over-reaching in its impacts. INT-006-2: PJM supports the FERC proposal to ensure that the correct functional entities are mandated to approve each transaction. PJM would note that RCs are already mandated by IRO-005-2 R2 to monitor all transactions. And R3 to ensure all TOPs and BAs are notified of any added transactions that would cause an operating limit violation not identified by the TOP. Thus the current INT and IRO standards, as written, allow transactions to be implemented as long as those transactions do not impact Operating Limits. In addition, the current standards mandate monitoring, not direct involvement of RCs, in each transaction. This approach allows reliability to be maintained without adding unnecessary administrative overhead on RCs.
Arizona Public	Yes	

Organization	Question 1:	Question 1 Comments:
Service Company (AZPS)		
FirstEnergy	Yes	We agree. Standards should only be applicable to an owner, operator or user of the bulk power system, and until these standards include this important concept, reliability of the BES will not be ensured.
PPL EnergyPlus		
WECC	Yes	Coordination of Interchange between Balancing Authorities and Transmission Operators is required for proper frequency control, control of flow on the transmision system and overall reliable operation of the Bulk Electric System. The current INT Standards as a whole do not assign clear responsibility to a user owner or operator of the Bulk Electric System for ensuring coordination. In addition the current INT Standards to not adequately recognize that the reliability impact of individual interchange transactions may vary depending on the magnitude of the transaction, the timing of the requests, the type of request and the current operational state of the Bulk Electric System
Response:		

2. Do you agree with the scope of the proposed standard action?

Organization	Question 2:	Question 2 Comments:
NPCC	No	Although the proposed SAR addresses several issues that would improve Interchange Standards, it should more clearly address the need for clarity on whether the Interchange Authority function is an entity or a function. Towards this end the scope of the SAR should incorporate the functions of the Interchange Authority and establish the Balancing Authority as the responsible entity for the Interchange Authority function.
AEP	No	We agree with the description of the modifications needing to be addressed. The combining of the requirements into a fewer number of standards for chronological flow and reference is an excellent idea and response to identified issues. It does not seem realistic for the sink BA to be responsible for the IA applicability, based on the present NERC IA definition. Business practices and reliability requirements for the scheduling of interchange of pseudo-ties and dynamic schedules need to be addressed and identified in these Standards because of their true real-time impact on the reliability of the Bulk Electric System. Just because an operating or Market entity can move a resource into a Balancing Area electronically or on paper, the resource and its flow impact is still directly related to the physical location and actual flow. Reliably managing congestion is about the true physical flow of resource to the load. If the requirements and business practices to address the reliability impact of dynamic transfers and pseudo-ties are not captured in the reliability standards or tools, reliability will continue to be compromised because the true cause of the congestion will not be properly identified. Not to mention the fact that other operating and Market entities might be unfairly managing congestion and penalized. As long as these two mechanisms for interchange transfer are identified and recognized in the monitoring and reliability assessment requirements and tools, they can be managed for reliable planning and real-time operation of the Bulk Electric System. If not, they become an unidentified burden to the real-time operation and compromise reliability. There should be requirements for modeling and managing the congestion impact of these resources in the NERC Reliability Standards.
CAISO	Yes	
SERC OC Standards Review Group	Yes	
Ameren	Yes	
Independent Electricity System Operator - Ontario	Yes	We generally agree with the scope.
We Energies	Yes	With the addition of removing the applicability of the CIP standards to the IA function.
Operating	Yes	

Organization	Question 2:	Question 2 Comments:
Reliability Working Group (ORWG)		
Great River Energy	No	INT -001-2 - Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" INT -006-2 - TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for ETag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour? INT-008-2 & INT-009-1 -No. The requirements in the standards that deal with the Interchange Authority are primarily those tasks done by e-tagging services and not Balancing Authorities. For example, INT-005-2 R1. and R1.1. both state actions that are completed by e-tagging services. This is a problem that was created by an incorrect conversion of Policy 3 into the V0 standards.
MRO NERC Standards Review Subcommittee (NSRS)	No	INT -001-2 - Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" INT -006-2 - TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for ETag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour?INT-008-2 & INT-009-1 -No. The requirements in the standards that deal with the Interchange Authority are primarily those tasks done by e-tagging services and not Balancing Authorities. For example, INT-005-2 R1. and R1.1. both state actions that are completed by e-tagging services. This is a problem that was created by an incorrect conversion of Policy 3 into the V0 standards.
OPPD	Yes	
Bonneville Power Administration	Yes	
Functional Model Working Group	Yes	We generally agree with the scope.
Manitoba Hydro	No	The brief description of the scope does not touch on the necessity to address the issues surrounding dynamically scheduling capacity type schedules. Capacity type transactions using dynamic schedules, need to be assured deliverability. Tagging capacity type transactions at "average expected MW profile values" can create problems, because standard transmission tariff anti-hoarding processes, automatically release unscheduled firm transmission service to the non-firm ATC. SOLs or IROLs could very well be exceeded.
PacifiCorp	Yes	
Duke energy	No	The scope of the SAR seems too large for one drafting team. Rather than using a phased approach the project should be broken up into separate projects.
Tennessee Valley	Yes	INT-008-2 and INT-009-1: TVA agrees with the comment that the standard requirement assigns the requirement

Organization	Question 2:	Question 2 Comments:
Authority		to the BA and not an e-tag spec. The e-tag spec is not a tool, only specifications of what the tool should be capable of doing.
Midwest ISO Stakeholders Standards Collaborators	No	Regarding INT-001-2, no, we do not agree. Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" Regarding INT-006-2, no, we do not agree. TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for E-Tag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour? Regarding INT-008-2 and INT-009-1, no, we do not agree. The requirements in the standards that deal with the Interchange Authority are primarily those tasks done by e-tagging services and not Balancing Authorities. For example, INT-005-2 R1. and R1.1. both state actions that are completed by e-tagging services. This is a problem that was created by an incorrect conversion of Policy 3 into the V0 standards.
PJM Interconnection	No	PJM does not see a need to rewrite the current standards, but does agree that there is a need to provide a final interpretation for the requirements in question. Thus the scope of the SAR is incorrect.
Arizona Public Service Company (AZPS)	Yes	I agree that clarity is needed in the standards in order to implement them and address issues within FERC Order 693. I don't think that the interchange authority must be a physical entity, but can be a software implementation of the process without requiring the vendor to be labeled as a functional entity.
FirstEnergy	No	Our answer to Question 2 is actually "Yes and No" - Comment: See our other comments.
PPL EnergyPlus		
WECC	Yes/No	In general I agree that the items identified in the scope should be addressed but are concerned that the scope is too large, too diverse, and encompasses too many separate standards to be achievable in a reasonable amount of time. I believe this SAR should focus on what is identified as the first phase of this project related to correct assignment of responsibility to a user owner or operator of the Bulk Electric System, I would also support expanding this phase one scope to include ensuring the individual requirements and violation severity levels are proportional to the impact on reliability and the incorporation of directives from FERC Order 693 where these directives relate to assignment of responsibility to user, owners or operators of the BES, The remainder of scope would be more appropriately addressed in a separate SAR.
Response:		

3. Do you agree with the applicability of the proposed standard action? If not, what functional entities do you think need to be added/deleted?

Organization	Question 3:	Question 3 Comments:
NPCC	No	The Resource Planner and Generator Operator Reliability Functions should not be included.
AEP	No	With the evolution from responsibilities of the previous traditional Control Area to present specific entities in the NERC functional model, ownership for some of the responsibilities to ensure reliable operation of the Bulk Electric System has been lost or left to gray areas of implied assumption. The present Balancing Authority functional entity no longer owns or directly controls all of the resources and interchange schedules, as it once did in the prior traditional utility and control area model. Since the Interchange Authority software tool has evolved to become the primary source of communication, coordination, and distribution for request for interchange to be reliably assessed and implemented into the ACE equation, all reliability functional entities need to be properly modeled in the tool and involved in the assessment validation process. If the applicability to the specific reliability functional entity is going to be identified in the NERC Reliability Standard, then the electronic software and Interchange Authority tool must have that particular entity on the approval rights path. This is not necessarily always true today, nor does the IA software match the NERC functional model. A Market affiliate or Creating Purchasing Selling Entity can submit an E-Tag in which a Generator Operator or designee is not involved in the E-tag reliability assessment validation process. This can lead to invalid and misleading approval from the remaining reliability functional entities, such and the BA and TO because the actual Generator Operator resource is not physically capable of matching generation to submitted E-Tag schedule time and ramp. Thus, the former traditional utility/CA and now BA becomes the default provider with the burden to balance and regulate for reliability performance criteria. Generation Operators with submitted resource plans should be in the E-Tag reliability assessment, validation, and approval process to ensure the resource can match what the PSE submits on an E-Tag as the request for interchange. If not, the PSE should have some applicability and accountability as a functional reliability entity for compliance. Remember, prior the new NERC functional model the reliability operators within the old traditional Control Area did the purchasing and selling with reliability being the primary focus, instead of financial. Since the PSE now performs that function, there has to be some direct applicability and accountability in the NERC BAL and INT Reliability Standards or the other responsible functional reliability entities are compromised. The Interchange Authority tool and E-Tag applicability, requirements, and specifications should be referenced in the NERC Reliability Standard. The present IA tool does not exactly match the reliability functional entities. There is still reference to Load and Generation Control Area, instead of the functional model's responsible reliability entities, such as the BA, TO, & GO etc. TP, a Transmission Planner in the NERC registered functions (is a Transmission Provider in the IA tool?). Therefore, there should be strong argument for the proposed SAR and identifying the proper reliability functional entities and accountability ownership.

Organization	Question 3:	Question 3 Comments:
CAISO	Yes	
SERC OC Standards Review Group	No	What is the justification for these standards to be applicable to the Resource Planner function? We believe it should be deleted.
Ameren	Yes	
Independent Electricity System Operator - Ontario	No	We disagree with including Resource Planner and Generator Operator as applicable entities. These entities are not assigned any requirements in these standards, nor are they expected to be assigned any responsibilities given the scope of the proposed changes.
We Energies	Yes	The specific responsibilities of the BA and IA need to be clear. There should not be a "default" responsible entity of the BA. If vendors are the key entities, it should be clear in the standards.
Operating Reliability Working Group (ORWG)	No	We are struggling trying to determine why the Resource Planner and Generator Operator are included on the applicability list. Also why isn't the Load-Serving Entity included on the list?
Great River Energy	No	The activities in the Interchange standards need to clearly identify the responsible entity. GRE believes the Interchange Authority (IA) requirements should be retired.
MRO NERC Standards Review Subcommittee (NSRS)	No	The activities in the Interchange standards should clearly identify the responsible entity. The MRO believes the Interchange Authority (IA) requirements should be retired.
OPPD	Yes	
Bonneville Power Administration	Yes	
Functional Model Working Group	No	We disagree with including Resource Planner and Generator Operator as applicable entities. These entities are not assigned any requirements in these standards, nor are they expected to be assigned any responsibilities given the scope of the proposed changes.
Manitoba Hydro	Yes	If it can not be clearly defined who the Interchange Authority is (change the glossary definition) then the IA requirements should be removed or rewritten assigning those responsibilities to another Function type ie: RC or BA.
PacifiCorp		PacifiCorp agrees that there is confusion regarding the Interchange Authority function and that clarity is needed regarding which entities should have responsibility for the activities currently applicable to the Interchange Authority. However, PacifiCorp is concerned with the proposal that one individual party to a transaction be identified as the responsible entity for interchange transactions, either through making the IA requirements

Organization	Question 3:	Question 3 Comments:
		applicable to the Sink Balancing Authority or by requiring that individual entities register as an Interchange Authority. PacifiCorp foresees two significant problems with this arrangement: 1) identifying and tracking, and taking responsibility for, only those transactions for which the Balancing Authority is the Sink will be administratively impossible without a new automated tool and will result in a potentially confusing scenario whereby many entities are responsible for transactions over a single interchange; and 2) designating only one party to a transaction as responsible for the interchange transaction could engender biased decision-making on the part of each responsible entity. PacifiCorp strongly believes that it makes much more common sense to designate a neutral third-party as responsible for the system-wide accuracy of actual and scheduled interchanges. PacifiCorp believes the Reliability Coordinator is the logical entity to fit this role, particularly because an automated tool already exists which performs the interchange authority functions.
Duke energy	No	We don't understand why the Resource Planner is included as an applicable entity.
Tennessee Valley Authority	No	TVA believes that the Interchange Authority as an entity should be removed, and the functional model should be changed to show the IA functions as belonging to the sink BA.
Midwest ISO Stakeholders Standards Collaborators	No	We believe the Interchange Authority function should be deleted from the functional model (FM), as it just causes confusion.
PJM Interconnection	No	See response to FERC directives in Question 1.
Arizona Public Service Company (AZPS)	No	Not sure of the applicability of the Resource Planner or Generator Operator. They've no involvement in interchange transactions not already covered by an existing function.
FirstEnergy	No	FE has the following issues with the applicability: 1. FERC has directed NERC to make the applicability of the approval of interchange transaction tags to the Transmission Operator due to their local area view of the reliability impacts of an interchange transaction and the Reliability Coordinator due to their wide area view. This will impact several entities by requiring installation of new E-Tag terminals and institute a tag approval procedure. Since the pervue of the reliability standards is bulk electric system reliability, we question the need for a local area view approval of an E-Tag since by definition the impacts are local and should not have an impact on BES reliability. The RC wide area view and approval should be sufficient. 2. We do not agree with the applicability to the Generator Operator and Resource Planner:- Historically the GOP has not been charged with interacting with E-tags. The view has always been that the sink entity is the beneficiary of the service and therefore bears the burden of submitting the tag. Per the NERC Functional Model Version 3,

Organization	Question 3:	Question 3 Comments:
		the GOP function merely "receives notice from the PSE if an interchange transaction is approved or denied", and if approved, "provides the BA and TOP with the requested amount of reliability-related services".- The RP does not have any direct responsibilities in the coordination of interchange transactions and should not be directly responsible for any requirements in these interchange standards. Per the NERC Functional Model Version 3, the RP function merely "coordinates with and collects data for resource planning from the Load-Serving Entities, Generator Owners, Generator Operators, Transmission Owners, Transmission Operators, Interchange Authorities, and Regional Reliability Organizations". 3. The LSE is equivalent to a PSE in many respects but not all LSEs are PSEs so the applicability section should include the LSE function.
PPL EnergyPlus		
WECC	No	Disagree with applicability Resource Planner, and Generation Operator, Believe Applicability should include Load Serving Entity. Also disagree with applicability to Interchange Authority, instead standard should allow flexibility for requirements currently assigned to Interchange Authority to be assigned to a Balancing Authority, ISO, RTO or RSG with a default assignment to the Sink Balancing Authority in the event no other user owner or operator of the BES agrees to accept responsibility.

4. If you are aware of any Regional Variances associated with the proposed standard action, please identify them here.

Organization	Question 4:
NPCC	Not aware of any variances.
AEP	
CAISO	
SERC OC Standards Review Group	
Ameren	
Independent Electricity System Operator - Ontario	
We Energies	none
Operating Reliability Working Group (ORWG)	We are not aware of any regional variances.
Great River Energy	None that we are aware of.
MRO NERC Standards Review Subcommittee (NSRS)	
OPPD	
Bonneville Power Administration	
Functional Model Working Group	None.
Manitoba Hydro	
PacifiCorp	PacifiCorp is concerned that in other regions of the country where independent system operators are more prevalent, it may make more sense for Sink Balancing Authorities to be responsible for interchange schedules or other currently identified Interchange Authority responsibilities. In areas where there is an independent operator, that operator may logically take responsibility for interchange schedules as an uninterested party. In the West, without an independent operator, determining which party should be responsible for each transaction is much more difficult as described above.
Duke energy	None
Tennessee Valley Authority	None
Midwest ISO Stakeholders Standards Collaborators	
PJM Interconnection	No

Organization	Question 4:
Arizona Public Service Company (AZPS)	I don't believe that the WECC has requested a Region Variance for it's business practices.
FirstEnergy	At this time, we are not aware of any Regional Variances associated with the proposed standard action. However, the SAR should leave it open for the SDT to explore this during the standard development process.
PPL EnergyPlus	
WECC	No

5. If you are aware of the need for a business practice to support the proposed standard action, please identify it here.

Organization	Question 5:
NPCC	The development of business practices for TLRs is already included in the current NAESB 2008 Annual Work Plan, under Item 1.a.ii.
AEP	
CAISO	
SERC OC Standards Review Group	
Ameren	
Independent Electricity System Operator - Ontario	
We Energies	
Operating Reliability Working Group (ORWG)	Nothing comes to mind at this time. Seeing something in writing, once the SDT posts draft standards, may trigger a response.
Great River Energy	
MRO NERC Standards Review Subcommittee (NSRS)	
OPPD	
Bonneville Power Administration	
Functional Model Working Group	None.
Manitoba Hydro	
PacifiCorp	Not aware of any.
Duke energy	None
Tennessee Valley Authority	None
Midwest ISO Stakeholders Standards Collaborators	
PJM Interconnection	The development of business practices for TLRs is already included in the current NAESB 2008 Annual Work Plan, under Item 1.a.ii.
Arizona Public Service Company (AZPS)	Yes, the WECC has implemented Business Practice Standards that add further clarity and require greater involvement in the interchange process in order to facilitate correct interchange checkout/coordination.
FirstEnergy	At this time, we are not aware of any need for a business practice to support the proposed standard action. However, the SAR should leave it open for the SDT to explore this during the standard development process.
PPL EnergyPlus	

Organization	Question 5:
WECC	If Standard is not revised to mandate a specific software application, business practices may be required to ensure software and communications compatability between the various entities (such as the e-tag specification), Business practices may be required to identify useful but purely administrative or commercial requirements which should be removed from the reliabilty standards.
Response:	

6. If you have any other comments on this SAR that you haven't already provided in response to the previous questions, please provide them here.

Organization	Question 6:
NPCC	The SAR places emphasis on the issue of requirements being assigned to either owners, operators, or users of the BPS and not to the so called ' tools' (i.e., etag) used to coordinate interchange; currently the Interchange Scheduling and Coordination Standards seem to properly assign these requirements to the owners, operators or users and not to industry tools used in interchange. Therefore, including this issue in the SAR, would seem to deflect the focus of the SAR away from the primary issue of Balancing Authority versus Interchange Authority clarification.
AEP	Since the Reliability Coordinator is responsible for the real-time operating wide area view and is actively involved in managing interchange through the IDC software tool for reliability, why shouldn't the RC be in the required front-end reliability assessment approval process and timing table? Would it not be more prudent to have a true reliability assessment window with the RC involved on the front-end, instead of curtailing NSI on the back-end with the IDC after a reliability limit is already exceeded? If the SAR is going to revise the stated INT-Reliability Standards, the submittal and allotted time for the functional reliability entities should be revisited to provide a true reliability assessment window for responsible entities. The timing table should not be Market driven. The proper responsible functional reliability entities should all be included in the applicability requirements and table. The suggestion to make a Sink Balancing Authority(s) the responsible entity for the an entire Interchange Authority process does not seem to be very realistic or possible. Would it not be more prudent to make an entity at the regional or wide area level, such as MISO, PJM, & SPP CBA, the responsible entity for having the process and software tool with specific requirements to the vendor to meet the IA reliability requirements? Better yet maybe NERC should become the Interchange Authority responsible for the process and requirements of communicating and distributing to the other functional reliability entities, as it does with the IDC. The NERC delimitation of IA itself implies that the responsibility for authorization to and between the BAs occurs at the higher regional and wide area level, so why suggest consideration for the responsible party to be a sink BA?
CAISO	
SERC OC Standards Review Group	
Ameren	
Independent Electricity System Operator - Ontario	The SAR proposes to consider requiring the Sink Balancing Authority responsibility for Interchange Authority functions, using an interchange transaction tool process as defined in the latest approved version of the e-Tag Specifications. We suggest the SDT to keep the options open, and consider the various aspects of possibility, for example, an independent entity to register as the IA to perform such function for transactions sourcing from or

Organization	Question 6:
	sinking in a Balancing Authority area. We suggest the SDT consult the Functional Model Working Group on this issue.
We Energies	
Operating Reliability Working Group (ORWG)	We feel that pseudo-ties should be treated comparably to dynamic schedules regarding reliability curtailments. The omission statement in Section 3.4 on page SAR-11 seems to indicate it may be acceptable to exclude pseudo-ties in curtailment considerations.
Great River Energy	All of the requirements applicable to the IA (except CIP) were tagging process steps in Policy 3 that were converted to IA requirements in the Version-0 effort. There is not a common understanding of what the IA is. Since these are tagging process steps and tagging tools aren't users, owners, or operators, the requirements should be retired or moved to an informational document. The IA function should be retired from the functional model (FM), as it just causes confusion. The BA's responsibilities for scheduling are already defined in the other INT standards. The final action would be to remove the IA as an applicable entity from the CIP standards. If NERC feels the tagging vendors should be held to the CIP standards, they should deal with them directly, and at the same time approach the IDC, SDX, GADS, CERTS and other vendors of NERC-supporting tools.
MRO NERC Standards Review Subcommittee (NSRS)	The activities in the Interchange standards should clearly identify the responsible entity. The MRO believes the Interchange Authority (IA) requirements should be retired. All of the requirements applicable to the IA (except CIP) were tagging process steps in Policy 3 that were converted to IA requirements in the V0 effort. There is not a common understanding of what the IA is. Since these are tagging process steps and tagging tools aren't users, owners, or operators, the requirements should be retired or moved to an informational document. The IA function should be retired from the functional model (FM), as it just causes confusion. The BA's responsibilities for scheduling are already defined in the other INT standards. The final action would be to remove the IA as an applicable entity from the CIP standards. If NERC feels the tagging vendors should be held to the CIP standards, they should deal with them directly, and at the same time approach the IDC, SDX, GADS, CERTS and other vendors of NERC-supporting tools.
OPPD	The first paragraph under the psuedo-tie section reads: Pseudo-Ties Pseudo-ties are often employed to assign generators, loads, or both from the balancing area to which they are physically connected into a balancing area that has effective operational control of them. What does "effective operational control" mean? Should we add a definition of it to the NERC Glossary of Terms? There are a lot of wind farms that are jointly owned or are under long term PPA's. Many of these these arrangements utilize psuedo ties to transfer power from the source to the sink control area. To my knowledge, wind farms don't use AGC. I don't think this committee meant to set the bar of "effective operational control" at AGC control, but maybe we should put any questions about that to rest? To my knowledge, the typical control that a host control area would have over a wind turbine is the ability to turn individual wind turbines on or off by feathering their blades. This could be done remotely, or may have to be done by dispatching personnel to the wind farm site. A sink control area thus would have to call the host control area to request 1 or more wind turbines be feathered to reduce output to the psuedo-tie. An additional issue with this type

Organization	Question 6:
	of control is that it common for a company to buy say 10 MWS of a 50 MWS wind farm. EMS typically would model the sink control area to get 20% of the wind farm output. Thus, if a sink control area called and requested the host control area to feather a 5 MW turbine, it would not cut the pseudo-tie reading by 5 MWS, instead it would cut the pseudo-tie reading by 1 MW (20% of 5). The term "effective operational control" would seem to suggest a more rigorous type of control than that typically exhibited by pseudo-tied wind farms. I don't think it was the committee's goal to outlaw existing psuedo-tied wind farms, so I feel we may need to flesh out what "effective operational control" means or simply replace the phrase with something less strict.
Bonneville Power Administration	Dynamic Schedules and Pseudo Ties are very similar in their nature and in their impact on the BES. Whether the transfer is an "Interchange" transaction, "AGC interchange", or a "Non-contiguous Pool Tie" is purely semantics. Both types of transfer involve the movement of power from one point in an interconnection to another. Both involve a variable power signal transmitted via telemetry. Both require that transmission rights be secured in order to move that power from source to sink. And, most importantly, both influence power flowing across flowgates and interties, and thus reliability. Despite the physical similarities, Attachment 2 defines two separate processes for providing information necessary for system reliability. Dynamic schedules have a well defined requirement which includes the submission of e-tags. Pseudo Ties, on the other hand, require no e-tags but rather have a relatively undefined process stating only that BA's must get the information to the IDC, Reliability Coordinator, etc. Dynamic Schedules and Pseudo Ties should have the same requirements for tagging even though they are treated differently in the ACE equation. The Reliability Authority has a need for information on both types of transfers and that information should be collected in a uniform, standardized manner. To do otherwise places one of these similar products at a disadvantage to the other and may violate the first Market Interface Principle - "A reliability standard shall not give any market participant an unfair competitive advantage." The drafting team should strive to find a single process for all dynamic transfers which, gets the necessary information onto the screen of the Reliability Coordinator and others who need this information in a manner which is least disruptive to the operations of BA's involved.
Functional Model Working Group	The SAR proposes to consider requiring the Sink Balancing Authority to be responsible for the Interchange Authority functions, using an interchange transaction tool process as defined in the latest approved version of the e-Tag Specifications. The FMWG supports the notion that the revised set of Coordinate Interchange standards shall ensure that each requirement is assigned to a responsible entity and not to a tool used to coordinate interchange. Many responsible entities employ tools to perform their respective functional tasks. For examples: the Balancing Authority uses tools such as AGC; the Reliability Coordinator and Transmission Operator use tools such as State Estimation and contingency analysis, etc. The tools that an Interchange Authority employs are simply a means to fulfill its obligations like its BA, RC and TOP counterparts. As such, the Interchange Authority should be held accountable for ensuring the interchange information is compiled and communicated timely and properly to facilitate implementation of interchange transactions, in the same way that its BA, RC and TOP counterparts are held accountable for ensure reliable operations of the bulk electric system using whatever tools they see necessary to perform their tasks. On the other hand, we do not agree that the sink BA should be the only

Organization	Question 6:
	entity required in the Coordinate Interchange standards to be responsible for the Interchange Authority functions. Such a restriction would preclude any third party from stepping forward to offer and register for this function - a scenario as described in the Functional Model's Technical Document. We believe the Coordinate Interchange standards should continue to assign the tasks and responsibilities to the Interchange Authority (as the Applicable Entity). The issue with who should register as the Interchange Authority can be addressed by the registration criteria. For transactions sinking in a Balancing Authority area, if no one steps forward to perform the Interchange Authority functions, the default entity is the sink BA. Under this condition, the sink BA should register as the default Interchange Authority for its area.
Manitoba Hydro	Comments regarding INT-001 and INT-004: NERC standards INT-001 and INT-004 require dynamic schedules be tagged at the hourly expected value (INT-001) and adjusted after-the-fact based upon magnitude (INT-004). Dynamic schedules used for capacity type transactions such as AGC regulation, contingency reserves or price sensitive market dispatch should be exempt from these requirements due to their intended purpose. Transmission service both day-ahead and real-time by releasing the unused transmission capacity not scheduled under existing transmission reservations. The unused and available transmission capacity is calculated based upon the maximum hourly capacity of the transmission reservation less its hourly scheduled interchange on interchange transaction tags. Tagging dynamic schedules at average expected values (below maximum values) artificially creates non-firm transmission capacity. This can lead to a situation where SOL and/or IROL levels are exceeded when dynamic schedules are dispatched in excess of their tagged average values and non-firm flows from implemented interchange transactions (a result of transmission capacity freed up from dynamic schedules being tagged at less than their maximum dispatch level) are simultaneously flowing. An example of capacity type transactions on dynamic schedules can be found in the Midwest ISO ancillary services market (expected to launch Sept 9, 2008). In this market External Asynchronous Resources will be dispatched to deliver energy and operating reserves utilizing dynamic interchange schedules tagged at the hourly maximum value. Due to the impending launch of the MISO ancillary services market in September 2008 it is imperative this dynamic scheduling issue be addressed in phase one of this project.
PacifiCorp	None at this time.
Duke energy	We agree that the Dynamic Transfer Reference Document should be left as a reference document and should not become part of the standards.
Tennessee Valley Authority	
Midwest ISO Stakeholders Standards Collaborators	The activities in the Interchange standards should clearly identify the responsible entity. The Midwest ISO believes the Interchange Authority (IA) requirements should be retired. All of the requirements applicable to the IA (except CIP) were tagging process steps in Policy 3 that were converted to IA requirements in the V0 effort. There is not a common understanding of what the IA is. Since these are tagging process steps and tagging tools

Organization	Question 6:
	aren't users, owners, or operators, the requirements should be retired or moved to an informational document. The IA function should be retired from the functional model (FM), as it just causes confusion. The BA's responsibilities for scheduling are already defined in the other INT standards. The final action would be to remove the IA as an applicable entity from the CIP standards. If NERC feels the tagging vendors should be held to the CIP standards, they should deal with them directly, and at the same time approach the IDC, SDX, GADS, CERTS and other vendors of NERC-supporting tools.
PJM Interconnection	There is a real need to distinguish between Functional Entities and Registration of entities. The IA is a set of reliability tasks that must be performed because without verification by all parties to a transaction there is the potential for inappropriate generation changes caused by incorrect transaction information. The IA tasks can be (but do not have to be) carried out independently of the BA tasks. As the Interchange Subcommittee notes, there can be technological changes in the future. PJM agrees and believes that the current INT standards allow for those changes; and to implement the IS's proposed changes, would preclude a non-BA entity from being an IA. This is a clear violation of the Market Principles 2 and 3.The NERC registration process must ensure that someone is held responsible for each mandated task. NERC can not hold a third-party vendor responsible to comply, but it can hold the entity that uses that third party entity. In lieu of an independent entity/entities registering as IAs, PJM fully supports the registration of BAs as being responsible for complying with the IA tasks.
Arizona Public Service Company (AZPS)	If it is felt that a physical entity must register and take responsibility as the IA, then it is our belief that the WECC, as the contract holder for the software used to perform all the IA functions within the Western Interconnection, would be that entity. But for clarity, it is our belief that the wording in the Functional Model and in the standards is out of step with the reality of present circumstances and that with software being robust and as practical as possible 100 percent available, there is no need for an IA in the FM or Standards.
FirstEnergy	FE has the following additional comments: 1. The SAR proposes to, "Consider requiring the Sink Balancing Authority responsibility for Interchange Authority functions, using an interchange transaction tool process as defined in the latest approved version of the E-Tag Specifications." The rules applied to this tool through the E-Tag Specifications are mostly designed to facilitate the application of Transmission Transaction market rules (many of the transmission transaction market rules ultimately facilitate the energy transactions market) which for the most part support the transmission and energy markets and are not applicable to improving reliability. We suggest a revision to the SAR to point only to the parts of the specifications related to reliability and not just include the E-Tag Specifications as a whole. Also, the E-Tag tool is similar to an EMS system in that it is a tool that is used to provide and promote BES reliability. These standards should be no more invasive then the requirements on network analysis or similar systems contained in an EMS tool. 2. Coordination with other projects and SDTs:- The SAR should indicate some type of coordination with the CIP SDT since the CIP-002 through CIP-009 places requirements on the Interchange Authority. The CIP standards

Organization	Question 6:
	will also need to point to the correct owner, operator or user of the BES for the Interchange functions.- NERC Project 2007-14 is in the process of revising INT-005-2, INT-006-2, and INT-008-2. The INT SDT will need to be aware of the latest versions of these standards when they revise all of the INT standards. 3. Definitions - The SAR should also include a review of the current NERC Glossary terms related to interchange to determine if any revisions or new definitions are necessary as a result of the interchange standards development. 4. The SAR indicates "The work in this project should be done in two phases, with the first phase focused solely on clarifying the applicability of each requirement in the existing set of standards. All other revisions should take place in a second phase." FE questions the feasibility of re-assigning the applicability of existing requirements to other NERC Functional Model responsible entities without the ability to concurrently modify requirements to better reflect the real-world interchange transaction process. This concern seems to be supported by the SARs earlier claim that: a) the Interchange Authority function as defined by the Functional Model does not represent technological advances since the FMWG originally defined the IA function b) A potential need for requirement references to the E-Tagging process that is presently in practice within industry. 5. FE agrees with the SAR purpose indicating that "Revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange; ... " In FE's comments to the FMWG related to proposed FM Ver 4 we indicated "The FMWG should give consideration to removing the IA from the FM. The IA Tasks should be re-oriented as needed to the TSP and/or BA entities. The IA does not appear to be a self evident entity to the extent that registration to the IA function will occur. The IDC should be viewed as a tool, not a Functional Model entity, used by the TSP and/or BA to accomplish the described tasks." To this end, we believe the SAR should indicate that the SDT, being comprised of subject matter experts and having reviewed and assessed comments, opinions from a variety of industry stakeholders will at the conclusion of the project provide its recommendation to the FMWG related to the on-going need of the IA functional entity classification.
PPL EnergyPlus	INT-001-3 Interchange Transaction Tagging Applicability :Reliability Coordinators need to be included because curtailments of dynamic schedules (covered under INT-004-2) will help reduce unscheduled flow and the RC is responsible to be sure that the data on the tag is enough to assure the right tags get curtailed (i.e. zone data, etc.). The Transmission Service Provider may also need to be included because this same logic may apply to conditional firm curtailments.R2.2: The west uses automatic time-error correction which pays inadvertent back

Organization	Question 6:
	continuously. The magnitude is usually a % of L10 and does not take manual intervention so it might be hard to tag. Should there be an exemption under R2.2 for the WECC time error correction?INT-003-2 Interchange Transaction ImplementationR1: it looks like "net" interchange was inserted then removed. Net is probably useful in this requirement.R1.1: The word RAMP may be useful to have in this section as the sending/receiving BA's must agree on RAMP details.INT-004-2 Interchange Transaction Modifications. It is interesting to note that dynamic schedule tags must be modified if the reserved capacity isn't being fully utilized or more transfer capability is needed (since +/- 10% and +/- 25 MWH covers both more and less than reserved amount). How (practically) will the dynamic schedule get more capacity that reserved? Does this standard need to link to the MOD-001 standard for calculating ATC? It doesn't appear that dynamic schedules deserve any higher priority than any other TSR. Should there be no allowance to exceed reserved capacity (i.e. +0%, -10%) Pre-R1: Do dynamic schedule curtailments need to be addressed in this standard? R2.3: The word "deadband" may be useful here to state an amount beyond which the tag must be modified.INT-005-2 Interchange Authority Distributes Arranged Interchange. This standard only addresses curtailments; does another standard address initiating an emergency tags (as when calling on reserves or starting a quick-start unit, etc.). R1.1: Distribute to all BA's on tag, not just source and sink BA's, otherwise losses supplied by intermediary BA's will cause inadvertent for the intermediary BAs. INT-006-2 response to Interchange Authority. No Comments. INT-007-1 Interchange Confirmation. No Comments. INT-008-2 Interchange Authority Distributes Status. No Comments. I NT-009-1 Implementation of Interchange. No Comments
WECC	Due to the large volume of transaction requests which must be processed, timely communication, assessment, approval and implementation of Interchange requires some type of software or automated process. SAR should ensure standards do not assume or require 100% availability of these systems for compliant operation should address the impact of a failure or malfunction of software or communication systems, and possibly include alternate standard requirements that would allow for reliable and compliant operation during short duration software or communication failures. INT Standards should recognize that implementation of transactions (or failure to implement transactions) needed for immediate system reliability such as curtailments, reloads, emergency assistance and deployment of contingency reserves. have a greater reliability impact than routine commercial transactions, particularly forward transactions or market adjustments. This should be considered when establishing standard requirements and violation severity levels for non-compliance.

Consideration of Comments on SAR to Modify and Update Coordinate Interchange Standards — Project 2008-12

The Coordinate Interchange SAR Drafting Team (CI SARDT) thanks all commenters who submitted comments on the first draft of the SAR to modify and update Coordinate Interchange standards. The SAR was posted for a 30-day public comment period from July 2, 2008 through July 31, 2008. The stakeholders were asked to provide feedback on the SAR through a special Electronic Standard Comment Form. There were 24 sets of comments, including comments from more than 90 different people from approximately 90 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on stakeholder comments, the SAR DT has made the following modifications to the SAR:

- Revised the "Purpose" section to reflect the need to address communications between functional entities related to reloading interchange transactions due to different operational conditions
- Revised the "Industry Need" section to note the need to add definitions for the terms used to reference Pseudo-ties and the need to review existing definitions related to interchange to determine if any revisions or new definitions are necessary as a result of the Interchange standards development.
- Revised the "Industry Need" section to clarify that the work in the project may be conducted in more than two phases.
- Revised the "Brief Description" section to clarify that within the project consideration should be given to requiring "each Sink Balancing Authority or its designee" (rather than "the Sink Balancing Authority") responsibility for providing the Interchange Authority functions using an interchange transaction tool process as defined in the latest approved version of the e-Tag Specifications.
- Revised the "Brief Description" section to clarify that within the project consideration should be given to adding specific references to the e-Tagging applications and tools as well as to the e-Tagging processes in the requirements
- Expanded the scope to include the possibility of making conforming changes to the applicability section of CIP-002-1 through CIP-009-1 if the industry determines that the Interchange Authority function is not performed by an "owner, operator or user" of the bulk electric system.
- Removed the "Resource Planner" as an applicable function, and added the Load-serving Entity as a "possible" applicable function.

In this report, the comments have been sorted so it is easier to see where there is consensus on the questions posed. The comments can be viewed in their original format at the following site:

http://www.nerc.com/filez/standards/Project2008-12_Coordinate_Interchange_Stds_Modifications.html

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.	Guy Zito	NPCC RSC										x

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Thompson	Consolidated Edison Co. of New York, Inc.	NPCC	1
2.	David Kiguel	Hydro One Networks Inc.	NPCC	1
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Frederick White	Northeast Utilities	NPCC	1
5.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
6.	Ron Falsetti	Independent Electricity System Operator	NPCC	2
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Randy MacDonald	New Brunswick System Operator	NPCC	2
9.	Gregory Campoli	New York Independent System Operator	NPCC	2
10.	Michael Ranalli	National Grid	NPCC	3
11.	Ronald E. Hart	Dominion Resources, Inc.	NPCC	5
12.	Ralph Rufrano	New York Power Authority	NPCC	5
13.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
14.	Michael Gildea	Constellation Energy	NPCC	6
15.	Brian D. Evans-Mongeon	Utility Services	NPCC	6
16.	Donald E. Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
17.	Brian Hogue	NPCC	NPCC	10
18.	Alan Adamson	New York State Reliability Council	NPCC	10
19.	Guy Zito	NPCC	NPCC	10
20.	Lee Pedowicz	NPCC	NPCC	10
21.	Gerry Dunbar	NPCC	NPCC	10

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
2.	Thad Ness	American Electric Power	x		x		x	x				
3.	Robert Sullivan	California ISO		x								
4.	Jim S. Griffith	SERC OC Standards Review Group	x		x		x					

Additional Member	Additional Organization	Region	Segment Selection	
1.	Robert Thomasson	Big Rivers Electric Cooperative	SERC	1, 3, 5
2.	Jim Case	Entergy	SERC	1, 3, 5
3.	Raymond Vice	Southern Co.	SERC	1, 3, 5

Additional Member		Additional Organization	Region	Segment Selection
4.	Marc Butts	Southern Co.	SERC	1, 3, 5
5.	J. T. Wood	Southern Co.	SERC	1, 3, 5
6.	Mike Oatts	Southern Co.	SERC	1, 3, 5
7.	Jim Busbin	Southern Co.	SERC	1, 3, 5
8.	Roman Carter	Southern Co.	SERC	1, 3, 5
9.	Carter Edge	SERC Reliability Corp.	SERC	10
10.	John Troha	SERC Reliability Corp.	SERC	10

	Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10
5.	Jeffery V. Hackman	Ameren	x									
6.	Ron Falsetti	Ontario IESO		x								
7.	Anthony Jankowski	We Energies			x	x	x					
8.	Robert Rhodes	SPP – Operating Reliability Working Group (ORWG)	x	x	x	x	x					

Additional Member		Additional Organization	Region	Segment Selection
1.	John Boshears	City Utilities, Springfield, MO	SPP	1, 3, 5
2.	Brian Berkstresser	Empire District Electric	SPP	1, 3, 5
3.	Bill Bateman	East Texas Electric Coop	SPP	3, 4
4.	Lisa Carter	Southwest Power Pool	SPP	2
5.	Mike Gammon	Kansas City Power & Light	SPP	1, 3, 5
6.	Don Hargrove	Oklahoma Gas & Electric	SPP	1, 3, 5
7.	Danny McDaniel	CLECO	SPP	1, 3, 5
8.	Kyle McMenamin	Southwestern Public Service	SPP	1, 3, 5
9.	Eddy Reece	Rayburn Country Electric Coop	SPP	3, 4
10.	Robert Rhodes	Southwest Power Pool	SPP	2

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Joe Knight	Great River Energy	x		x		x	x				
10.	Marie Knox	MRO NERC Standards Review Subcommittee (NSRS)		x								

Additional Member		Additional Organization	Region	Segment Selection
1.	Neal Balu	Wisconsin Public Service	MRO	3, 4, 5, 6
2.	Terry Bilke	Midwest ISO Inc.	MRO	2
3.	Carol Gerou	Minnesota Power	MRO	1, 3, 5, 6
4.	Jim Haigh	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Tom Mielnik	MidAmerican Energy Company	MRO	1, 3, 5, 6
7.	Pam Sordet	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Larry Brusseau	Midwest Reliability Organization	MRO	10
13.	Mike Brytowski	Midwest Reliability Organization	MRO	10

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Shane Jenson	Omaha Public Power District	x		x		x				x	
12.	Denise Koehn	Bonneville Power Administration	x		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.	Wes Hutchison	Transmission Operational Analysis & Support	WECC	1
2.	Kristy Humphrey	Power Scheduling Coordination	WECC	3, 5, 6
3.	Fran Halpin	Generation Support	WECC	3, 5, 6
4.	Bart McManus	Transmission Technical Operations	WECC	1
5.	Troy Simpson	Transmission Bus Process & Implementation	WECC	1
6.	Joel Jenck	Power Scheduling Coordination	WECC	3, 5, 6

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
13.	Jim Cyrulewski	Functional Model Working Group								x		
14.	Kris Manchur	Manitoba Hydro	x		x		x	x				
15.	Sandra Shaffer	PacifiCorp	x		x		x					
16.	Greg Rowland	Duke Energy Corp.	x		x		x	x				
17.	Eric Grau	Tennessee Valley Authority									x	
18.	Marie Knox	Midwest ISO Stakeholders Standards Collaborators		2								

Additional Member	Additional Organization	Region	Segment Selection	
1.	Nicholas Browning	Midwest ISO	RFC	2
2.	Barb Kedrowski	We Energies	RFC	3, 5
3.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
4.	Joe Dobes	NIPSCO	RFC	1
5.	Roger Huhn	NIPSCO	RFC	6
6.	Bill SeDoris	NIPSCO	RFC	3
7.	Kirit Shah	Ameren	SERC	1
8.	Sam Ciccone	First Energy	RFC	1
9.	Dave Folk	First Energy	RFC	1
10.	Rob Martinko	First Energy	RFC	1
11.	Doug Hohlbaugh	First Energy	RFC	1

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
19.	Patrick Brown	PJM Interconnection, L.L.C.		x								
20.	Mark W. Hackney	Arizona Public Service Company (AZPS)	x									
21.	Sam Ciccone	FirstEnergy	x	x		x		x				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Doug Hohlbaugh	FE	RFC	1, 3, 5, 6
2.	Dave Folk	FE	RFC	1, 3, 5, 6
3.	Rob Martinko	FE	RFC	1, 3, 5, 6
4.	Larry Hartley	FES	RFC	3

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
22.	Mark Heimbach	PPL EnergyPlus						x				

Additional Member	Additional Organization	Region	Segment Selection	
1.	John Cummings	PPL EnergyPlus	WECC	6

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
23.	Steve Ruechert	WECC										x
24.	Raymond Vojdani	WAPA										

1. Do you agree that there is a reliability-related reason for the proposed standard action?

Summary Consideration: Most commenters agreed with the requesters that there is a reliability-related reason to support the proposed standard action.

Organization	Question 1:	Question 1 Comments:
MRO NERC Standards Review Subcommittee (NSRS)		Please note that question 1 is different than the word form provided on the website. The word comment form states, "Do you agree that there is a reliability-related reason for the proposed standard action?" and offers the options of Yes, No, and Yes and No. Our group responded with "Yes and No" and offered the comments listed below:INT-001-2 - Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" INT-006-2 - TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for ETag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour?INT-008-2 - Yes.
Response: The CI SARDT appreciates the identification of the discrepancies between the comment form and the website. The CI SARDT also thanks you for your comments. The SAR is intended to frame the parameters for the standard drafting team. The SAR does not get into the details that your comments address. The CI SARDT requests that you track the progress of the standard drafting team (SDT) to ensure that your concerns are addressed. The inclusion of the Reliability Coordinator (RC) has been directed by FERC in Order 693. The CI SARDT prefers letting the SDT determine the appropriate Functional Model (FM) entity. See the SAR "Purpose" and "Industry Need."		
Great River Energy	No	INT-001-2 - Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" INT-006-2 - TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for ETag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour? INT-008-2 - Yes.
Response: The CI SARDT thanks you for your comments. The SAR is intended to frame the parameters for the standard drafting team. The SAR does not get into the details that your comments address. The CI SARDT requests that you track the progress of the SDT to ensure that your concerns are addressed. The inclusion of the RC has been directed by FERC in Order 693. The CI SARDT prefers letting the SDT determine the appropriate FM entity. See the SAR "Purpose" and "Industry Need."		
Duke energy	No	The scope of the SAR appears administrative, and not reliability-related. However we do believe the standards need to be revised to address those items.
Response: The CI SARDT appreciates your comments. As part of the SAR, numerous requirements are considered administrative and will be addressed by the Standard Drafting Team (SDT). See Attachment #1.		
Midwest ISO	No	Regarding INT-001-2, no, we do not agree. Since Market Flow is included in TLR cuts, this suggestion is

Organization	Question 1:	Question 1 Comments:
Stakeholders Standards Collaborators		overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" Regarding INT-006-2, no, we do not agree. TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. System conditions that require RC action are typically assessed in real-time, past the requirement for E-Tag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour? Regarding INT-008-2, yes, we agree.
Response: The CI SARDT thanks you for your comments. The SAR is intended to frame the parameters for the standard drafting team. The SAR does not get into the details that your comments address. The CI SARDT requests that you track the progress of the SDT to ensure that your concerns are addressed. The inclusion of the Reliability Coordinator (RC) has been directed by FERC in Order 693. The CI SARDT prefers letting the SDT determine the appropriate FM entity. See the SAR “Purpose” and “Industry Need.”		
PJM Interconnection	No	Regarding the purpose of the SAR as stated in the body of the SAR (i.e. not including FERC directives): (i) The stated purpose of the SAR (the last sentence in the PURPOSE section) is "to revise …INT standards to reflect that the IA functions ARE performed by an automated system rather then an entity." (ii) PJM believes that NERC standards are written as mandatory obligations assigned to registered entities that in turn are responsible for performing those tasks and who are subject to non-compliance penalties. Thus the stated purpose (to reflect/assign the IA tasks to an automated system) conflicts with that concept. (iii) PJM also believes that NERC Interpretations are used to explain implementation issues. Thus the SAR's stated purpose, as noted above, would fall into this latter category. (iv) PJM agrees that it is appropriate to change and/or revise existing requirements to ensure that each requirement is assigned to an owner or operator of the bulk power system and not to a tool. Thus we agree with the stated justification in that same PURPOSE section, that is, there is a need to "resolve the discrepancy" and the confusion related to the IA Function. But there is not so much a need for a change in the standards as there is for an interpretation of those standards. (v) PJM supports NERC's current standards that identify the reliability need for verifying Interchange transactions and that recognize that group of tasks as a unique functional set of tasks that CAN BE assigned and complied with by an entity that can be (but not necessarily is) an RC, BA, or any other registered entity. Moreover, PJM supports the NERC registration process that in the absence of any one or more entities agreeing to register as an IA, and until one or more entities register as IAs, to register all BAs to be responsible for those tasks assigned in the INT standards to the IA Function. Regarding Attachment 1 to the SAR:

<table>
<tr><th>Organization</th><th>Question 1:</th><th>Question 1 Comments:</th></tr>
<tr><td></td><td></td><td>Attachment 1 (FERC Order 693)

FERC Order 693 under INT-001-2, Interchange Information, directs NERC to "include a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and 'non-Order No. 888' transfers."

(vi) PJM supports internal Network transactions and does not recognize internal point-to-point transfers within our Balancing Authority area. All previous grandfathered point-to-point transactions have been closed out. While PJM does support the tracking of interchange in, out, or through a balancing authority as necessary, PJM opposes any attempt to redefine Network transactions as point-to-point transactions particularly since Network market flow is already included in TLR cuts, thus this suggestion is over-reaching in its impacts.

(vii) INT-006-2: PJM supports the FERC proposal to ensure that the correct functional entities are mandated to approve each transaction. PJM would note that RCs are already mandated by IRO-005-2 R2 to monitor all transactions. And R3 to ensure all TOPs and BAs are notified of any added transactions that would cause an operating limit violation not identified by the TOP. Thus the current INT and IRO standards, as written, allow transactions to be implemented as long as those transactions do not impact Operating Limits. In addition, the current standards mandate monitoring, not direct involvement of RCs, in each transaction. This approach allows reliability to be maintained without adding unnecessary administrative overhead on RCs.</td></tr>
<tr><td colspan="3">Response: The CI SARDT thanks you for your comments. Please see the CI SARDT responses:
(i) The CI SARDT appreciates the note. As clarification, the CI SARDT believes the statement is made in the last sentence in the first paragraph of the “Industry Need.”
(ii) The CI SARDT agrees with your comment. Please see the “Purpose” statement.
(iii) An interpretation would be sufficient. However, since the INT standards are being thoroughly revised, making the standards unambiguous, the revision will ensure the requirements are crisp and clear.
(iv) An interpretation would be sufficient. However since the INT standards are being thoroughly revised, making the standards unambiguous, the revision will ensure the requirements are crisp and clear.
(v) The CI SARDT appreciates the comment. The registration of the IA entities is outside of the scope of this SAR. NERC Compliance Group is responsible for registration of the IA.
(vi) The CI SARDT agrees that point-to-point transfers need to be addressed by this SAR based on FERC Order 693. The applicable TLR standards are addressed in standard IRO-006 and will not be added to the SAR.
(vii) The CI SARDT concurs with the comment. The CI SARDT believes the SAR is adequately written and will not seek a FERC comment change. The standard drafting team will determine the extent of the revision.</td></tr>
<tr><td>AEP</td><td>Yes</td><td>The applicability for the responsible functional reliability entity needs to be more realistic to the actual operating model and include any entities that can impact or compromise the ability to ensure reliability.</td></tr>
</table>

Organization	Question 1:	Question 1 Comments:
Response: The CI SARDT agrees with the comment. Please see the SAR "Purpose" statement.		
We Energies	Yes	Must have clear responsibilities in standards.
Response: The CI SARDT agrees with the comment. Please see the SAR "Purpose" statement.		
Tennessee Valley Authority	Yes	TVA agrees with the comment that referring to e-tag only describes the requirements and technical specifications to implement an electronic transaction information system. It provides a basis for tools designed to facilitate interchange transaction information between two parties. It does not specify "the tool," only what the tool must be capable of doing.INT-001-2: TVA is in favor of including a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers. Although the IDC does not currently use this information, the BAs use it in their forward reliability analysis.
Response: The CI SARDT agrees that point-to-point transactions need to be addressed by the SAR (based on FERC Order 693). The applicable point-to-point standards have been added to the SAR.		
FirstEnergy	Yes	We agree. Standards should ony be applicable to an owner, operator or user of the bulk power system, and until these standards include this important concept, reliability of the BES will not be ensured.
Response: The CI SARDT agrees. Please see the "Purpose" statement.		
WECC	Yes	Coordination of Interchange between Balancing Authorities and Transmission Operators is required for proper frequency control, control of flow on the transmision system and overall reliable operation of the Bulk Electric System. The current INT Standards as a whole do not assign clear responsibility to a user owner or operator of the Bulk Electric System for ensuring coordination. In addition the current INT Standards to not adequately recognize that the reliability impact of individual interchange transactions may vary depending on the magnitude of the transaction, the timing of the requests, the type of request and the current operational state of the Bulk Electric System
Response: The CI SARDT agrees. Please see the "Purpose" statement. The CI SARDT intent is to remove ambiguity from the standards and incorporate crisp and clear language into the INT standard requirements.		
NPCC	Yes	Regional interchange and improving the clarity of functional responsibilities among entities has a direct impact on reliability.
Response: The CI SARDT thanks you for the comment and concurs with the comment.		
Arizona Public Service Company (AZPS)	Yes	
WAPA	Yes	
CAISO	Yes	
SERC OC Standards Review Group	Yes	

Organization	Question 1:	Question 1 Comments:
Ameren	Yes	
Independent Electricity System Operator - Ontario	Yes	
Operating Reliability Working Group (ORWG)	Yes	
Manitoba Hydro	Yes	
PacifiCorp	Yes	
OPPD	Yes	
Bonneville Power Administration	Yes	
Functional Model Working Group	Yes	

2. Do you agree with the scope of the proposed standard action?

Summary Consideration: Several stakeholders indicated disagreement with the scope of the proposed SAR based on the presumption that the work would be assigned to a single drafting team. The decision as to whether the work should be assigned to a single drafting team or to multiple teams rests with the Standards Committee.

Several stakeholders indicated the scope should address reloading interchange transactions due to different operational conditions, and the drafting team modified the purpose section of the SAR to include this.

Several commenters indicated that the SAR should address some of the requirements contained within IRO-006 and the SAR DT did not adopt this suggestion as there is already an effort underway to modify IRO-006.

One commenter indicated that the SAR should be expanded to include the conforming changes that may be necessary if the industry determines that requirements should not be assigned to the IA function. The SAR was modified to include this expansion. The CIP standards and several real-time operating standards include requirements assigned to the IA.

Organization	Question 2:	Question 2 Comments:
WAPA	Yes and No	There needs to be additional requirements to address the following: (i) Clearly define the requirements of reliability entities involved in curtailing and reloading interchange transactions due to different operational conditions. (ii) The new requirements need to address the differences in the cause for a curtailment and the communications required. For example, while the loss of a generator may warrant an immediate curtailment of interchange, the loss of the transmission elements may warrant a few minutes delay before curtailment so that the TOP can be given an opportunity to put the outage element back into service. If a TOP's effort to restore the device fails, then the TOP or the TSP should be allowed to curtail the schedules from the time of trip. (iii) Certain curtailments issued by reliability entities should not require any approval. Furthermore, with the advance of e-tagging and widespread use of e-tag, there might not be a need for telephone coordination between approving entities since some of today's transactions involve numerous BAs and TSPs.
Response: The CI SARDT thanks you for your comments. (i) The CI SARDT agrees that reloads need to be addressed by this SAR. TLRs are addressed by IRO-006 and are outside the scope of this SAR. (ii) The CI SARDT concurs with the comment. "To define the communications on reloading interchange transactions due to different operational conditions;" has been added to the SAR "Purpose."		

Organization	Question 2:	Question 2 Comments:
(iii) The CI SARDT appreciates the comment.		
NPCC	No	Although the proposed SAR addresses several issues that would improve Interchange Standards, it should more clearly address the need for clarity on whether the Interchange Authority function is an entity or a function. Towards this end the scope of the SAR should incorporate the functions of the Interchange Authority and establish the Balancing Authority as the responsible entity for the Interchange Authority function.
Response: Thank you for your comment. The CI SARDT believes the essence of the comment is captured in the enhanced/revised SAR "Purpose" statement. The SDT may recommend to the industry whether the sink BA is the designated IA or not.		
AEP	No	We agree with the description of the modifications needing to be addressed. The combining of the requirements into a fewer number of standards for chronological flow and reference is an excellent idea and response to identified issues. It does not seem realistic for the sink BA to be responsible for the IA applicability, based on the present NERC IA definition. Business practices and reliability requirements for the scheduling of interchange of pseudo-ties and dynamic schedules need to be addressed and identified in these Standards because of their true real-time impact on the reliability of the Bulk Electric System. Just because an operating or Market entity can move a resource into a Balancing Area electronically or on paper, the resource and its flow impact is still directly related to the physical location and actual flow. Reliably managing congestion is about the true physical flow of resource to the load. If the requirements and business practices to address the reliability impact of dynamic transfers and pseudo-ties are not captured in the reliability standards or tools, reliability will continue to be compromised because the true cause of the congestion will not be properly identified. Not to mention the fact that other operating and Market entities might be unfairly managing congestion and penalized. As long as these two mechanisms for interchange transfer are identified and recognized in the monitoring and reliability assessment requirements and tools, they can be managed for reliable planning and real-time operation of the Bulk Electric System. If not, they become an unidentified burden to the real-time operation and compromise reliability. There should be requirements for modeling and managing the congestion impact of these resources in the NERC Reliability Standards.
Response: The CI SARDT appreciates your comments. For the support to combine and reduce the number of INT standards. The SAR will leave the determination of the IA to the SDT (see SAR "Purpose"). The CI SARDT concurs that the NERC reliability INT standards have a reliability impact on the bulk power system and the reliability requirements need to be retained. The CI SARDT concurs with the dynamic transfers and pseudo-ties comments. The CI SARDT agrees that reloads need to be added to this SAR. The SAR "Purpose" section has been modified, however the TLR standard, IRO-006 is independent of this SAR and has not been added to the SAR.		
Great River Energy MRO NERC Standards Review	No	(i) INT -001-2 - Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" (ii) INT -006-2 - TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007.

Organization	Question 2:	Question 2 Comments:
Subcommittee (NSRS)		(iii) System conditions that require RC action are typically assessed in real-time, past the requirement for ETag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour? INT-008-2 & INT-009-1 -No. (iv) The requirements in the standards that deal with the Interchange Authority are primarily those tasks done by e-tagging services and not Balancing Authorities. For example, INT-005-2 R1. and R1.1. both state actions that are completed by e-tagging services. This is a problem that was created by an incorrect conversion of Policy 3 into the V0 standards.
Response: Thank you for your comments. The CI SARDT responses are: (i) Defining reloads due to different operational conditions has been added to the SAR "Purpose" section. TLR standard, IRO-006, is independent of this SAR and will not be added to the SAR. (ii) The SDT will review current standard requirements and consolidate standards and requirements where possible. Existing redundancy should be eliminated. (iii) Regarding the RC comment, Attachment 1 has a FERC Order 693 generic statement on RC review and directives. The CI SARDT will not seek FERC clarification on the Order at this time. The CI SARDT suggests that a similar comment be made when when the SDT posts its recommended revised draft standards. (iv) This SAR attempts to address ambiguous INT standard requirements.		
Manitoba Hydro	No	The brief description of the scope does not touch on the necessity to address the issues surrounding dynamically scheduling capacity type schedules. Capacity type transactions using dynamic schedules, need to be assured deliverability. Tagging capacity type transactions at "average expected MW profile values" can create problems, because standard transmission tariff anti-hoarding processes, automatically release unscheduled firm transmission service to the non-firm ATC. SOLs or IROLs could very well be exceeded.
Response: The CI SARDT appreciates and concurs with your comment. However, the SAR is intended to frame the standard at a much higher level (general description with less detail than you request). Your comment is recommended to be submitted to the SDT when the actual standards are drafted and posted for comment.		
Midwest ISO Stakeholders Standards Collaborators	No	(i) Regarding INT-001-2, no, we do not agree. Since Market Flow is included in TLR cuts, this suggestion is overreaching its intent. Specification to types of interchange can be supported, but not "all point-to-point?" (ii) Regarding INT-006-2, no, we do not agree. TSPs are already performing AFC calculations on the related TSRs. Those same TPs and BAs are already doing reliability assessments per INT-007. (iii) System conditions that require RC action are typically assessed in real-time, past the requirement for E-Tag submissions. What system conditions exist that will give an RC cause to approve or deny a transaction a month out? a day? an hour? Regarding INT-008-2 and INT-009-1, no, we do not agree.

Organization	Question 2:	Question 2 Comments:
		(iv) The requirements in the standards that deal with the Interchange Authority are primarily those tasks done by e-tagging services and not Balancing Authorities. For example, INT-005-2 R1. and R1.1. both state actions that are completed by e-tagging services. This is a problem that was created by an incorrect conversion of Policy 3 into the V0 standards.
Response: Thank you for your comments. The CI SARDT responses are: (i) Defining communications for reloads due to different operational conditions has been added to the SAR "Purpose" section. TLR standard, IRO-006, is independent of this SAR and will not be added to the SAR. (ii) The SDT will review current standard requirements and consolidate standards and requirements where possible. Existing redundancy should be eliminated. (iii) Regarding the RC comment, Attachment 1 has a FERC Order 693 generic statement on RC review and directives. The CI SARDT will not seek FERC clarification on the Order at this time. The CI SARDT suggests that a similar comment be made when the SDT posts its recommended revised draft standards. **(iv)** This SAR attempts to address ambiguous INT standard requirements.		
Duke energy	No	The scope of the SAR seems too large for one drafting team. Rather than using a phased approach the project should be broken up into separate projects.
Response: The CI SARDT thanks you for your comment. In order to "consider combining requirements into a fewer number of standards" (taken from the SAR "Brief Description" and "Detailed Description") it is necessary to review all of the INT standards at one time. The Scope of the SAR was determined by the NERC Standards Committee and not by the Interchange Subcommittee.		
PJM Interconnection	No	PJM does not see a need to rewrite the current standards, but does agree that there is a need to provide a final interpretation for the requirements in question. Thus the scope of the SAR is incorrect.
Response: The CI SARDT thanks you for your comment. The CI SARDT believes the issues presented in the SAR scope are significant including "Consider combining requirements into a fewer number of standards."		
FirstEnergy	No	Our answer to Question 2 is actually "Yes and No" - Comment: See our other comments.
Response: The CI SARDT appreciates your comments.		
WECC	Yes/No	In general I agree that the items identified in the scope should be addressed but are concerned that the scope is too large, too diverse, and encompasses too many separate standards to be achievable in a reasonable amount of time. I believe this SAR should focus on what is identified as the first phase of this project related to correct assignment of responsibility to a user owner or operator of the Bulk Electric System, I would also support expanding this phase one scope to include ensuring the individual requirements and violation severity levels are proportional to the impact on reliability and the incorporation of directives from FERC Order 693 where these directives relate to assignment of responsibility to user, owners or operators of the BES, The remainder of scope would be more appropriately addressed in a separate SAR.
Response: Thank you for your comment. The CI SARDT believes that your comment is one approach that can be pursued. However, in order to "consider combining requirements into a fewer number of standards" (taken from the SAR "Brief Description" and "Detailed Description") it is necessary to review all of the INT standards at one time. The Scope of the SAR was determined by the NERC Standards Committee and not by		

Organization	Question 2:	Question 2 Comments:
the Interchange Subcommittee.		
We Energies	Yes	With the addition of removing the applicability of the CIP standards to the IA function.
Response: The CI SARDT thanks you for your comment and agrees with your comment. If there are no tasks assigned to the Interchange Authority function, then the SDT will make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity. This has been added to the "Brief Description" and to the "Detailed Description."		
Independent Electricity System Operator - Ontario	Yes	We generally agree with the scope.
Response: The CI SARDT thanks you for your comment.		
Functional Model Working Group	Yes	We generally agree with the scope.
Response: The CI SARDT thanks you for your comment.		
Tennessee Valley Authority	Yes	INT-008-2 and INT-009-1: TVA agrees with the comment that the standard requirement assigns the requirement to the BA and not an e-tag spec. The e-tag spec is not a tool, only specifications of what the tool should be capable of doing.
Response: The CI SARDT appreciates your comment. The CI SARDT concurs with your comment. See the SAR "Purpose" section.		
Arizona Public Service Company (AZPS)	Yes	I agree that clarity is needed in the standards in order to implement them and address issues within FERC Order 693. I don't think that the interchange authority must be a physical entity, but can be a software implementation of the process without requiring the vendor to be labeled as a functional entity.
Response: The CI SARDT thanks you for your comment. The CI SARDT authored this SAR and one of the objectives was to address who should be responsible for the IA functional responsibilities. Your comment is appreciated as the CI SARDT finalizes the SAR for the SDT.		
CAISO	Yes	
SERC OC Standards Review Group	Yes	
Ameren	Yes	
Operating Reliability Working Group (ORWG)	Yes	
OPPD	Yes	
Bonneville Power Administration	Yes	

Organization	Question 2:	Question 2 Comments:
PacifiCorp	Yes	

3. Do you agree with the applicability of the proposed standard action? If not, what functional entities do you think need to be added/deleted?

Summary Consideration: Most stakeholders agreed with the proposed applicability with the exception of the Resource Planner and the Generator Operator. The SAR DT has removed the Resource Planner but has retained the Generator Operator. Some commenters indicated that there should be a requirement for the Generator Operator to confirm that its resource is physically capable of meeting the generation schedule time and ramp on the E-Tag. The SAR DT does not make any judgment as to whether there is a need for the proposed requirement, but the inclusion of the Generator Operator in the applicability section of the SAR will allow for such a requirement to be developed if stakeholders support this concept.

Organization	Question 3:	Question 3 Comments:
PacifiCorp		PacifiCorp agrees that there is confusion regarding the Interchange Authority function and that clarity is needed regarding which entities should have responsibility for the activities currently applicable to the Interchange Authority. However, PacifiCorp is concerned with the proposal that one individual party to a transaction be identified as the responsible entity for interchange transactions, either through making the IA requirements applicable to the Sink Balancing Authority or by requiring that individual entities register as an Interchange Authority. PacifiCorp foresees two significant problems with this arrangement: 1) identifying and tracking, and taking responsibility for, only those transactions for which the Balancing Authority is the Sink will be administratively impossible without a new automated tool and will result in a potentially confusing scenario whereby many entities are responsible for transactions over a single interchange; and 2) designating only one party to a transaction as responsible for the interchange transaction could engender biased decision-making on the part of each responsible entity. PacifiCorp strongly believes that it makes much more common sense to designate a neutral third-party as responsible for the system-wide accuracy of actual and scheduled interchanges. PacifiCorp believes the Reliability Coordinator is the logical entity to fit this role, particularly because an automated tool already exists which performs the interchange authority functions.
Response: The CI SARDT appreciates your comments. The CI SARDT believes that your comments support the "IA" clarification part of the SAR scope. The NERC Compliance Group needs to register the IAs. The Compliance Group has repeatedly said that the IA functions cannot be held by a tool. The CI SARDT appreciates your comment and believes the SAR "Purpose" captures your concern.		
FirstEnergy	No	FE has the following issues with the applicability: 1. FERC has directed NERC to make the applicability of the approval of interchange transaction tags to the Transmission Operator due to their local area view of the reliability impacts of an interchange transaction and the Reliability Coordinator due to their wide area view. This will impact several entities by requiring installation of new E-Tag terminals and institute a tag approval procedure. Since the pervue of the reliability standards is bulk electric system reliability, we question the need for a local area view approval of an E-Tag since by definition the

Organization	Question 3:	Question 3 Comments:
		impacts are local and should not have an impact on BES reliability. The RC wide area view and approval should be sufficient. 2. We do not agree with the applicability to the Generator Operator and Resource Planner:- Historically the GOP has not been charged with interacting with E-tags. The view has always been that the sink entity is the beneficiary of the service and therefore bears the burden of submitting the tag. Per the NERC Functional Model Version 3, the GOP function merely "receives notice from the PSE if an interchange transaction is approved or denied", and if approved, "provides the BA and TOP with the requested amount of reliability-related services".- The RP does not have any direct responsibilities in the coordination of interchange transactions and should not be directly responsible for any requirements in these interchange standards. Per the NERC Functional Model Version 3, the RP function merely "coordinates with and collects data for resource planning from the Load-Serving Entities, Generator Owners, Generator Operators, Transmission Owners, Transmission Operators, Interchange Authorities, and Regional Reliability Organizations". 3. The LSE is equivalent to a PSE in many respects but not all LSEs are PSEs so the applicability section should include the LSE function.
Response: Thank you for your comments. The CI SARDT responses are: 1. The CI SARDT believes the comment is relevant and will be addressed by the SDT. 2. The CI SARDT concurs with your Generator Operator comment. The Generator Operator will remain checked because support for the GO to be included in the SAR has been expressed and received in the comments. However, the Resource Planner will be un-checked on the SAR. **3.** The CI SARDT concurs with your comment. The LSE will be checked on the SAR.		
AEP	No	(i) With the evolution from responsibilities of the previous traditional Control Area to present specific entities in the NERC functional model, ownership for some of the responsibilities to ensure reliable operation of the Bulk Electric System has been lost or left to gray areas of implied assumption. The present Balancing Authority functional entity no longer owns or directly controls all of the resources and interchange schedules, as it once did in the prior traditional utility and control area model. Since the Interchange Authority software tool has evolved to become the primary source of communication, coordination, and distribution for request for interchange to be reliably assessed and implemented into the ACE equation, all reliability functional entities need to be properly modeled in the tool and involved in the assessment validation process. If the applicability to the specific reliability functional entity is going to be identified in the NERC Reliability Standard, then the electronic software and Interchange Authority tool must have that particular entity on the approval rights path. This is not necessarily always true today, nor does the IA software match the NERC functional model. A Market affiliate or Creating Purchasing Selling Entity can submit an E-Tag in which a Generator Operator or designee is not involved in the E-tag reliability assessment validation process. This can lead to invalid and misleading approval from the remaining reliability functional entities, such and the BA and TO because the actual Generator Operator resource is not

Organization	Question 3:	Question 3 Comments:
		physically capable of matching generation to submitted E-Tag schedule time and ramp. Thus, the former traditional utility/CA and now BA becomes the default provider with the burden to balance and regulate for reliability performance criteria. Generation Operators with submitted resource plans should be in the E-Tag reliability assessment, validation, and approval process to ensure the resource can match what the PSE submits on an E-Tag as the request for interchange. If not, the PSE should have some applicability and accountability as a functional reliability entity for compliance. Remember, prior the new NERC functional model the reliability operators within the old traditional Control Area did the purchasing and selling with reliability being the primary focus, instead of financial. Since the PSE now performs that function, there has to be some direct applicability and accountability in the NERC BAL and INT Reliability Standards or the other responsible functional reliability entities are compromised. (ii) The Interchange Authority tool and E-Tag applicability, requirements, and specifications should be referenced in the NERC Reliability Standard. The present IA tool does not exactly match the reliability functional entities. There is still reference to Load and Generation Control Area, instead of the functional model's responsible reliability entities, such as the BA, TO, & GO etc. TP, a Transmission Planner in the NERC registered functions (is a Transmission Provider in the IA tool?). Therefore, there should be strong argument for the proposed SAR and identifying the proper reliability functional entities and accountability ownership.
Response: Thank you for your comments. The CI SARDT responses are: (i) The CI SARDT has discussed the Generator Operator and decided to continue to include the GO in the SAR. Your support for the GO and the logic in your comments helped to persuade the CI SARDT to retain the GO. The CI SARDT suggests the SDT to reevaluate the GO applicability during the standards revision process. (ii) The CI SARDT believes the IA tools needs to be considered and possibly added or referenced in the SAR. The CI SARDT believes the “Brief Description” bullet “The existing requirements are tool-neutral. Consider adding specific references to the e-Tagging process in the requirements.” Captures the intent of your comment. The CI SARDT believes the IA tool vendors and users need to work together on the tool’s functions and descriptors. The IA tool specifications are outside the scope of this SAR.		
PJM Interconnection	No	See response to FERC directives in Question 1.
Response: The CI SARDT thanks you for your comment.		
Arizona Public Service Company (AZPS)	No	Not sure of the applicability of the Resource Planner or Generator Operator. They've no involvement in interchange transactions not already covered by an existing function.
Response: Thank you for your comment. The CI SARDT concurs with your comment to un-check the Resource Planner. However, support has been expressed by commenters to retain the Generator Operator in the SAR. The CI SARDT suggests the SDT revisit the applicability of the GO during the revision of the standards.		
NPCC	No	The Resource Planner and Generator Operator Reliability Functions should not be included.

Organization	Question 3:	Question 3 Comments:
Response: Thank you for your comment. The CI SARDT concurs with your comment to un-check the Resource Planner. However, support has been expressed by commenters to retain the Generator Operator in the SAR. The CI SARDT suggests the SDT revisit the applicability of the GO during the revision of the standards.		
SERC OC Standards Review Group	No	What is the justification for these standards to be applicable to the Resource Planner function? We believe it should be deleted.
Response: The CI SARDT appreciates your comment. The CI SARDT concurs with your comment. The Resource Planner has been un-checked on the SAR Applicability List.		
Independent Electricity System Operator - Ontario	No	We disagree with including Resource Planner and Generator Operator as applicable entities. These entities are not assigned any requirements in these standards, nor are they expected to be assigned any responsibilities given the scope of the proposed changes.
Response: Thank you for your comment. The CI SARDT concurs with your comment to un-check the Resource Planner. However, support has been expressed by commenters to retain the Generator Operator in the SAR. The CI SARDT suggests the SDT revisit the applicability of the GO during the revision of the standards.		
Functional Model Working Group	No	We disagree with including Resource Planner and Generator Operator as applicable entities. These entities are not assigned any requirements in these standards, nor are they expected to be assigned any responsibilities given the scope of the proposed changes.
Response: Thank you for your comment. The CI SARDT concurs with your comment to un-check the Resource Planner. However, support has been expressed by commenters to retain the Generator Operator in the SAR. The CI SARDT suggests the SDT revisit the applicability of the GO during the revision of the standards.		
Duke energy	No	We don't understand why the Resource Planner is included as an applicable entity.
Response: The CI SARDT appreciates your comment. The CI SARDT concurs with your comment. The Resource Planner has been un-checked on the SAR Applicability List.		
Operating Reliability Working Group (ORWG)	No	We are struggling trying to determine why the Resource Planner and Generator Operator are included on the applicability list. Also why isn't the Load-Serving Entity included on the list?
Response: Thank you for your comment. The CI SARDT concurs with your comment to un-check the Resource Planner. However, support has been expressed by commenters to retain the Generator Operator in the SAR. The CI SARDT suggests the SDT revisit the applicability of the GO during the revision of the standards.		
WECC	No	(i) Disagree with applicability Resource Planner, and Generation Operator, Believe Applicability should include Load Serving Entity. (ii) Also disagree with applicability to Interchange Authority, instead standard should allow flexibility for

Organization	Question 3:	Question 3 Comments:
		requirements currently assigned to Interchange Authority to be assigned to a Balancing Authority, ISO, RTO or RSG with a default assignment to the Sink Balancing Authority in the event no other user owner or operator of the BES agrees to accept responsibility.
Response: Thank you for your comments. The CI SARDT responses are: (i) Thank you for your comment. The CI SARDT concurs with your comment to un-check the Resource Planner. However, support has been expressed by commenters to retain the Generator Operator in the SAR. The CI SARDT suggests the SDT revisit the applicability of the GO during the revision of the standards. The CI SARDT concurs with your comment. The LSE will be checked on the SAR. **(ii)** The CI SARDT believes there is enough IA confusion in the INT standards to merit this SAR. The CI SARDT believes the concern is great enough to assign the first phase of the standard development to resolving the IA issue. Please refer to the SAR “Purpose” and “Industry Need” sections for languagae that supports your comment.		
Great River Energy	No	The activities in the Interchange standards need to clearly identify the responsible entity. GRE believes the Interchange Authority (IA) requirements should be retired.
Response: The CI SARDT believes there is enough IA confusion in the INT standards to merit this SAR. The CI SARDT believes the concern is great enough to assign the first phase of the standard development to resolving the IA issue. Please refer to the SAR “Purpose” and “Industry Need” sections for languagae that supports your comment.		
MRO NERC Standards Review Subcommittee (NSRS)	No	The activities in the Interchange standards should clearly identify the responsible entity. The MRO believes the Interchange Authority (IA) requirements should be retired.
Response: The CI SARDT believes there is enough IA confusion in the INT standards to merit this SAR. The CI SARDT believes the concern is great enough to assign the first phase of the standard development to resolving the IA issue. Please refer to the SAR “Purpose” and “Industry Need” sections for language that supports your comment.		
Midwest ISO Stakeholders Standards Collaborators	No	We believe the Interchange Authority function should be deleted from the functional model (FM), as it just causes confusion.
Response: Thank you for your comment. The content of and change process for the Functional Model is outside of he SAR and standards process.		
Tennessee Valley Authority	No	TVA believes that the Interchange Authority as an entity should be removed, and the functional model should be changed to show the IA functions as belonging to the sink BA.
Response: The CI SARDT believes there is enough IA confusion in the INT standards to merit this SAR. The CI SARDT believes the concern is great enough to assign the first phase of the standard development to resolving the IA issue. Please refer to the SAR “Purpose” and “Industry Need” sections for languagae that supports your comment. The content of and change process for the Functional Model is outside of he SAR and		

Organization	Question 3:	Question 3 Comments:
standards process.		
Manitoba Hydro	Yes	If it can not be clearly defined who the Interchange Authority is (change the glossary definition) then the IA requirements should be removed or rewritten assigning those responsibilities to another Function type ie: RC or BA.
Response: The CI SARDT believes there is enough IA confusion in the INT standards to merit this SAR. The CI SARDT believes the concern is great enough to assign the first phase of the standard development to resolving the IA issue. Please refer to the SAR "Purpose" and "Industry Need" sections for language that supports your comment.		
We Energies	Yes	The specific responsibilities of the BA and IA need to be clear. There should not be a "default" responsible entity of the BA. If vendors are the key entities, it should be clear in the standards.
Response: The CI SARDT believes there is enough IA confusion in the INT standards to merit this SAR. The CI SARDT believes the concern is great enough to assign the first phase of the standard development to resolving the IA issue. Please refer to the SAR "Purpose" and "Industry Need" sections for language that supports your comment.		
Ameren	Yes	
CAISO	Yes	
WAPA	Yes	
OPPD	Yes	
Bonneville Power Administration	Yes	

4. If you are aware of any Regional Variances associated with the proposed standard action, please identify them here.

Summary Consideration: None of the stakeholders who participated in this comment period indicated a need for any Regional Variance.

Organization	Question 4:
Arizona Public Service Company (AZPS)	I don't believe that the WECC has requested a Region Variance for it's business practices.
Response: Thank you for your comment.	
FirstEnergy	At this time, we are not aware of any Regional Variances associated with the proposed standard action. However, the SAR should leave it open for the SDT to explore this during the standard development process.
Response: Thank you for your comment. The CI SARDT concurs with your comment.	
NPCC	Not aware of any variances.
We Energies	none
Operating Reliability Working Group (ORWG)	We are not aware of any regional variances.
Great River Energy	None that we are aware of.
Functional Model Working Group	None.
Duke energy	None
Tennessee Valley Authority	None
PJM Interconnection	No
WECC	No

5. If you are aware of the need for a business practice to support the proposed standard action, please identify it here.

Summary Consideration: None of the stakeholders who responded to this question indicated a need for any new business practices to support the proposed SAR. Some stakeholders did indicate that, depending on the language in the requirements in the revised standards, there may be a need for modifications to business practices associated with the e-tag system.

Organization	Question 5:
NPCC	The development of business practices for TLRs is already included in the current NAESB 2008 Annual Work Plan, under Item 1.a.ii.
Response: The CI SARDT thanks you for your comment.	
Operating Reliability Working Group (ORWG)	Nothing comes to mind at this time. Seeing something in writing, once the SDT posts draft standards, may trigger a response.
Response: Thank you for your comment. The CI SARDT concurs.	
PJM Interconnection	The development of business practices for TLRs is already included in the current NAESB 2008 Annual Work Plan, under Item 1.a.ii.
Response: The CI SARDT thanks you for your comment.	
Arizona Public Service Company (AZPS)	Yes, the WECC has implemented Business Practice Standards that add further clarity and require greater involvement in the interchange process in order to facilitate correct interchange checkout/coordination.
Response: The CI SARDT thanks you for your comment. WECC has commented on this question. However, the WECC comment did not identify any business practices. Please identify any specific business practices in the next SAR posting.	
FirstEnergy	At this time, we are not aware of any need for a business practice to support the proposed standard action. However, the SAR should leave it open for the SDT to explore this during the standard development process.
Response: Thank you for your comment. The CI SARDT concurs.	
WECC	If Standard is not revised to mandate a specific software application, business practices may be required to ensure software and communications compatability between the various entities (such as the e-tag specification), Business practices may be required to identify useful but purely administrative or commercial requirements which should be removed from the reliabilty standards.
Response: Thank you. The CI SARDT recommends that the industry monitor the development of this SAR and standards development to determine if and when any business practices are necessary to support the SAR and standards.	
PacifiCorp	Not aware of any.
Duke energy	None
Tennessee Valley Authority	None
Functional Model Working Group	None.

6. If you have any other comments on this SAR that you haven't already provided in response to the previous questions, please provide them here.

Summary Consideration: Most comments provided were provided in response to earlier questions in this report. A stakeholder recommended that the SAR be expanded to include a review of the current NERC Glossary terms related to interchange to determine if any revisions or new definitions are necessary as a result of the interchange standards development and this suggestion was adopted.

A stakeholder indicated that dynamic schedule curtailments should be addressed in INT-001, and the SAR DT added this to the Industry Need section of the SAR.

Organization	Question 6:
WAPA	Under previous NERC Policies, specifically Policy 3, there were provisions that address how reliability adjustments (curtailments) were to be accomplished and the requirement for all entities to follow a Transmission Service Provider's (TSP's) curtailment request. Recently, there have been several cases of curtailment denials by the source or sink BAs. As long as there is no clearly defined standard or procedure describing appropriate curtailments of an interchange transaction, the reliability of the power system is left to interpretation by individual entities. If a Transmission Operator (TOP) or TSP (TSP) issues a curtailment to a confirmed interchange transaction, due to a fault on the transmission line, the trip of a DC tie between two Interconnections, or the loss of a generator, the curtailment should be accepted by all parties to the transaction. As indicated above, numerous instances of curtailment denial have been recorded due to an entity's interpretation of its own business practices and/or restrictions. The denial of a curtailment may cause reliability problems, such as generation/load imbalance or exceeding SOL or IROL limits.
Response: The CI SARDT appreciates your comment. TLR curtailments are addressed in IRO-006 and will not be addressed in this SAR. The CI SARDT suggests that you follow the development of the SDT and the revised INT standards and comment during the future postings. The CI SARDT believes communications on reloads need to be addressed by this SAR. The CI SARDT believes your comments are related to the IRO-006 standard and the CI SARDT suggests that you submit your comments to the TLR standard drafting team.	
NPCC	The SAR places emphasis on the issue of requirements being assigned to either owners, operators, or users of the BPS and not to the so called ' tools' (i.e., etag) used to coordinate interchange; currently the Interchange Scheduling and Coordination Standards seem to properly assign these requirements to the owners, operators or users and not to industry tools used in interchange. Therefore, including this issue in the SAR, would seem to deflect the focus of the SAR away from the primary issue of Balancing Authority versus Interchange Authority clarification.
Response: The CI SARDT believes there is enough IA confusion in the INT standards to merit this SAR. The CI SARDT believes the concern is	

Organization	Question 6:
great enough to assign the first phase of the standard development to resolving the IA issue. Please refer to the SAR "Purpose" and "Industry Need" sections for language that supports your comment.	
AEP	(i) Since the Reliability Coordinator is responsible for the real-time operating wide area view and is actively involved in managing interchange through the IDC software tool for reliability, why shouldn't the RC be in the required front-end reliability assessment approval process and timing table? Would it not be more prudent to have a true reliability assessment window with the RC involved on the front-end, instead of curtailing NSI on the back-end with the IDC after a reliability limit is already exceeded? (ii) (iii) If the SAR is going to revise the stated INT-Reliability Standards, the submittal and allotted time for the functional reliability entities should be revisited to provide a true reliability assessment window for responsible entities. The timing table should not be Market driven. (iv) The proper responsible functional reliability entities should all be included in the applicability requirements and table. (iv) The suggestion to make a Sink Balancing Authority(s) the responsible entity for the an entire Interchange Authority process does not seem to be very realistic or possible. Would it not be more prudent to make an entity at the regional or wide area level, such as MISO, PJM, & SPP CBA, the responsible entity for having the process and software tool with specific requirements to the vendor to meet the IA reliability requirements? Better yet maybe NERC should become the Interchange Authority responsible for the process and requirements of communicating and distributing to the other functional reliability entities, as it does with the IDC. The NERC delimitation of IA itself implies that the responsibility for authorization to and between the BAs occurs at the higher regional and wide area level, so why suggest consideration for the responsible party to be a sink BA?
Response: Thank you for your comments. The CI SARDT responses are: (i) Based on FERC Order 693, the RC is to be included in the front-end interchange approval process. The CI SARDT prefers letting the SDT determine the appropriate Functional Model entity to perform the IA responsibilities. See the SAR "Purpose" and "Industry Need". (ii) The Timing Tables just went through an urgent action revision. However, the Timing Tables should again be reviewed for accuracy. The CI SARDT agrees that the Timing Tables should not be market driven. However, you should be aware that identical Timing Tables are located in the NAESB business practice standards. (iii) The CI SARDT concurs. (iv) The CI SARDT believes the best entities to review and approve interchange transactions are the entities involved in the transactions. The RCs may be able to look at the Big Picture overview. But the RCs have different Functional Model responsibilities and time horizons.	
Independent Electricity System	The SAR proposes to consider requiring the Sink Balancing Authority responsibility for Interchange Authority

Organization	Question 6:
Operator - Ontario	functions, using an interchange transaction tool process as defined in the latest approved version of the e-Tag Specifications. We suggest the SDT to keep the options open, and consider the various aspects of possibility, for example, an independent entity to register as the IA to perform such function for transactions sourcing from or sinking in a Balancing Authority area. We suggest the SDT consult the Functional Model Working Group on this issue.
Response: The CI SARDT thanks you for your comments. The CI SARDT has attempted to frame the IA issue in the “Purpose” and “Industry Need” in order for the SDT to draft the standards. The NERC Compliance Group has started registering the IAs. The SDT may consult with the Functional Model Working Group in the future as you have proposed.	
Operating Reliability Working Group (ORWG)	We feel that pseudo-ties should be treated comparably to dynamic schedules regarding reliability curtailments. The omission statement in Section 3.4 on page SAR-11 seems to indicate it may be acceptable to exclude pseudo-ties in curtailment considerations.
Response: Thank you for your comment. The CI SARDT has attempted to frame the Dynamic Transfer issues so the SDT can draft the standards. The CI SARDT recommends that you monitor the SDT progress and standards development to ensure your concerns are addressed.	
Great River Energy	All of the requirements applicable to the IA (except CIP) were tagging process steps in Policy 3 that were converted to IA requirements in the Version-0 effort. There is not a common understanding of what the IA is. Since these are tagging process steps and tagging tools aren’t users, owners, or operators, the requirements should be retired or moved to an informational document. The IA function should be retired from the functional model (FM), as it just causes confusion. The BA’s responsibilities for scheduling are already defined in the other INT standards. The final action would be to remove the IA as an applicable entity from the CIP standards. If NERC feels the tagging vendors should be held to the CIP standards, they should deal with them directly, and at the same time approach the IDC, SDX, GADS, CERTS and other vendors of NERC-supporting tools.
Response: The CI SARDT appreciates your comments. The SDT will use the Functional Model as a “reference” but is not required to align its work with the Functional Model if the industry indicates that the Functional Model is not correct in its treatment of a specific issue. Drafting teams are encouraged to respect the Functional Model as this was developed with stakeholder input and does provide a framework where every reliability-related task is assigned to a functional entity. The CI SARDT has attempted to frame the IA issue in the “Purpose” and “Industry Need” so the SDT can draft the standards. The NERC Compliance Group has started registering the IAs. The Functional Model and the IA registration are outside the scope of the SAR and the standard development. The “Interchange Authority” language found in the Functional Model is outside the scope of this SAR. If there are no tasks assigned to the Interchange Authority function, then the SDT will make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity. This statement has been added to the SAR “Brief Description” and to the “Detailed Description.”	
MRO NERC Standards Review Subcommittee (NSRS)	The activities in the Interchange standards should clearly identify the responsible entity. The MRO believes the Interchange Authority (IA) requirements should be retired. All of the requirements applicable to the IA (except CIP) were tagging process steps in Policy 3 that were converted to IA requirements in the V0 effort. There is not a common understanding of what the IA is. Since these are tagging process steps and tagging tools aren’t users, owners, or operators, the requirements should be retired or moved to an informational document. The IA function

Organization	Question 6:
	should be retired from the functional model (FM), as it just causes confusion. The BA's responsibilities for scheduling are already defined in the other INT standards. The final action would be to remove the IA as an applicable entity from the CIP standards. If NERC feels the tagging vendors should be held to the CIP standards, they should deal with them directly, and at the same time approach the IDC, SDX, GADS, CERTS and other vendors of NERC-supporting tools.
Response: The CI SARDT appreciates your comments. The SDT will use the Functional Model as a "reference" but is not required to align its work with the Functional Model if the industry indicates that the Functional Model is not correct in its treatment of a specific issue. Drafting teams are encouraged to respect the Functional Model as this was developed with stakeholder input and does provide a framework where every reliability-related task is assigned to a functional entity. The CI SARDT has attempted to frame the IA issue in the "Purpose" and "Industry Need" so the SDT can draft the standards. The NERC Compliance Group has started registering the IAs. The Functional Model and the IA registration are outside the scope of the SAR and the standard development. The "Interchange Authority" language found in the Functional Model is outside the scope of this SAR. If there are no tasks assigned to the Interchange Authority function, then the SDT will make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity. This statement has been added to the SAR "Brief Description" and to the "Detailed Description."	
OPPD	The first paragraph under the psuedo-tie section reads: Pseudo-Ties Pseudo-ties are often employed to assign generators, loads, or both from the balancing area to which they are physically connected into a balancing area that has effective operational control of them. What does "effective operational control" mean? Should we add a definition of it to the NERC Glossary of Terms? There are a lot of wind farms that are jointly owned or are under long term PPA's. Many of these these arrangements utilize psuedo ties to transfer power from the source to the sink control area. To my knowledge, wind farms don't use AGC. I don't think this committee meant to set the bar of "effective operational control" at AGC control, but maybe we should put any questions about that to rest? To my knowledge, the typical control that a host control area would have over a wind turbine is the ability to turn individual wind turbines on or off by feathering their blades. This could be done remotely, or may have to be done by dispatching personnel to the wind farm site. A sink control area thus would have to call the host control area to request 1 or more wind turbines be feathered to reduce output to the psuedo-tie. An additional issue with this type of control is that it common for a company to buy say 10 MWS of a 50 MWS wind farm. EMS typically would model the sink control area to get 20% of the wind farm output. Thus, if a sink control area called and requested the host control area to feather a 5 MW turbine, it would not cut the pseudo-tie reading by 5 MWS, instead it would cut the pseudo-tie reading by 1 MW (20% of 5). The term "effective operational control" would seem to suggest a more rigorous type of control than that typically exhibited by pseudo-tied wind farms. I don't think it was the committee's goal to outlaw existing psuedo-tied wind farms, so I feel we may need to flesh out what "effective operational control" means or simply replace the phrase with something less strict.
Response: The CI SARDT appreciates your comment and concurs with your comments. The SAR is intended to frame the parameters for the SDT to draft the standards. The CI SARDT requests that you track the progress of the SDT to ensure your concerns are addressed.	
Bonneville Power Administration	Dynamic Schedules and Pseudo Ties are very similar in their nature and in their impact on the BES. Whether the transfer is an "Interchange" transaction, "AGC interchange", or a "Non-contiguous Pool Tie" is purely semantics.

Organization	Question 6:
	Both types of transfer involve the movement of power from one point in an interconnection to another. Both involve a variable power signal transmitted via telemetry. Both require that transmission rights be secured in order to move that power from source to sink. And, most importantly, both influence power flowing across flowgates and interties, and thus reliability. Despite the physical similarities, Attachment 2 defines two separate processes for providing information necessary for system reliability. Dynamic schedules have a well defined requirement which includes the submission of e-tags. Pseudo Ties, on the other hand, require no e-tags but rather have a relatively undefined process stating only that BA's must get the information to the IDC, Reliability Coordinator, etc. Dynamic Schedules and Pseudo Ties should have the same requirements for tagging even though they are treated differently in the ACE equation. The Reliability Authority has a need for information on both types of transfers and that information should be collected in a uniform, standardized manner. To do otherwise places one of these similar products at a disadvantage to the other and may violate the first Market Interface Principle - "A reliability standard shall not give any market participant an unfair competitive advantage." The drafting team should strive to find a single process for all dynamic transfers which, gets the necessary information onto the screen of the Reliability Coordinator and others who need this information in a manner which is least disruptive to the operations of BA's involved.
Response: Thank you. The CI SARDT concurs with your response. The SAR is intended to frame the parameters for the SDT to draft the standards. The CI SARDT requests that you track the progress of the SDT to ensure your concerns are addressed.	
Functional Model Working Group	The SAR proposes to consider requiring the Sink Balancing Authority to be responsible for the Interchange Authority functions, using an interchange transaction tool process as defined in the latest approved version of the e-Tag Specifications. The FMWG supports the notion that the revised set of Coordinate Interchange standards shall ensure that each requirement is assigned to a responsible entity and not to a tool used to coordinate interchange. Many responsible entities employ tools to perform their respective functional tasks. For examples: the Balancing Authority uses tools such as AGC; the Reliability Coordinator and Transmission Operator use tools such as State Estimation and contingency analysis, etc. The tools that an Interchange Authority employs are simply a means to fulfill its obligations like its BA, RC and TOP counterparts. As such, the Interchange Authority should be held accountable for ensuring the interchange information is compiled and communicated timely and properly to facilitate implementation of interchange transactions, in the same way that its BA, RC and TOP counterparts are held accountable for ensure reliable operations of the bulk electric system using whatever tools they see necessary to perform their tasks. On the other hand, we do not agree that the sink BA should be the only entity required in the Coordinate Interchange standards to be responsible for the Interchange Authority functions. Such a restriction would preclude any third party from stepping forward to offer and register for this function - a scenario as described in the Functional Model's Technical Document. We believe the Coordinate Interchange standards should continue to assign the tasks and responsibilities to the Interchange Authority (as the Applicable Entity). The issue with who should register as the Interchange Authority can be addressed by the registration criteria. For transactions sinking in a Balancing Authority area, if no one steps forward to perform the Interchange Authority functions, the default entity is the sink BA. Under this condition, the sink BA should register as the

Organization	**Question 6:**
	default Interchange Authority for its area.
Response: The CI SARDT believes your comment are very descriptive for the reason for the SAR. The CI SARDT has attempted to frame the IA issue in the SAR "Purpose" and "Industry Need" in order for the SDT to draft the standards. The goal is to make the standards less ambiguous and more crisp and clear.	
Manitoba Hydro	Comments regarding INT-001 and INT-004: NERC standards INT-001 and INT-004 require dynamic schedules be tagged at the hourly expected value (INT-001) and adjusted after-the-fact based upon magnitude (INT-004). Dynamic schedules used for capacity type transactions such as AGC regulation, contingency reserves or price sensitive market dispatch should be exempt from these requirements due to their intended purpose. Transmission service both day-ahead and real-time by releasing the unused transmission capacity not scheduled under existing transmission reservations. The unused and available transmission capacity is calculated based upon the maximum hourly capacity of the transmission reservation less its hourly scheduled interchange on interchange transaction tags. Tagging dynamic schedules at average expected values (below maximum values) artificially creates non-firm transmission capacity. This can lead to a situation where SOL and/or IROL levels are exceeded when dynamic schedules are dispatched in excess of their tagged average values and non-firm flows from implemented interchange transactions (a result of transmission capacity freed up from dynamic schedules being tagged at less than their maximum dispatch level) are simultaneously flowing. An example of capacity type transactions on dynamic schedules can be found in the Midwest ISO ancillary services market (expected to launch Sept 9, 2008). In this market External Asynchronous Resources will be dispatched to deliver energy and operating reserves utilizing dynamic interchange schedules tagged at the hourly maximum value. Due to the impending launch of the MISO ancillary services market in September 2008 it is imperative this dynamic scheduling issue be addressed in phase one of this project.
Response: Thank you for your comment. The CI SARDT has attempted to frame the Dynamic Transfer issues in order for the SDT to draft the standards. The CI SARDT recommends that you monitor the SDT progress and standards development to ensure your concerns are addressed.	
Duke energy	We agree that the Dynamic Transfer Reference Document should be left as a reference document and should not become part of the standards.
Response: Thank you. The CI SARDT concurs with your comment. However, the SDT may create Dynamic Schedule and Pseudo-Time reliability requirements.	
Midwest ISO Stakeholders Standards Collaborators	The activities in the Interchange standards should clearly identify the responsible entity. The Midwest ISO believes the Interchange Authority (IA) requirements should be retired. All of the requirements applicable to the IA (except CIP) were tagging process steps in Policy 3 that were converted to IA requirements in the V0 effort. There is not a common understanding of what the IA is. Since these are tagging process steps and tagging tools aren't users, owners, or operators, the requirements should be retired or moved to an informational document. The IA function should be retired from the functional model (FM), as it just causes confusion. The BA's

Organization	Question 6:
	responsibilities for scheduling are already defined in the other INT standards. The final action would be to remove the IA as an applicable entity from the CIP standards. If NERC feels the tagging vendors should be held to the CIP standards, they should deal with them directly, and at the same time approach the IDC, SDX, GADS, CERTS and other vendors of NERC-supporting tools.
Response: Thank you for your comment. The CI SARDT is bound by the Functional Model definition for the IA. The CI SARDT has attempted to frame the IA issue in the "Purpose" and "Industry Need" in order for the SDT to draft the standards. The Functional Model and the IA registration are outside the scope of the SAR and standard development.	
PJM Interconnection	There is a real need to distinguish between Functional Entities and Registration of entities. The IA is a set of reliability tasks that must be performed because without verification by all parties to a transaction there is the potential for inappropriate generation changes caused by incorrect transaction information. The IA tasks can be (but do not have to be) carried out independently of the BA tasks. As the Interchange Subcommittee notes, there can be technological changes in the future. PJM agrees and believes that the current INT standards allow for those changes; and to implement the IS's proposed changes, would preclude a non-BA entity from being an IA. This is a clear violation of the Market Principles 2 and 3.The NERC registration process must ensure that someone is held responsible for each mandated task. NERC can not hold a third-party vendor responsible to comply, but it can hold the entity that uses that third party entity. In lieu of an independent entity/entities registering as IAs, PJM fully supports the registration of BAs as being responsible for complying with the IA tasks.
Response: The CI SARDT appreciates your comments. The CI SARDT concurs with the comment for the need to distinguish between the Functional Model and registration of entities. The CI SARDT believes your comments are very descriptive for the reason for the SAR. The CI SARDT has attempted to frame the IA issue in the SAR "Purpose" and "Industry Need" so the SDT can draft the standards. The goal is to make the standards less ambiguous and more crisp and clear. The CI SARDT has attempted to frame the IA issue in the "Purpose" and "Industry Need" in order for the SDT to draft the standards. The NERC Compliance Group has started registering the IAs. The Functional Model and the IA registration are outside the scope of the SAR and standard development.	
Arizona Public Service Company (AZPS)	If it is felt that a physical entity must register and take responsibility as the IA, then it is our belief that the WECC, as the contract holder for the software used to perform all the IA functions within the Western Interconnection, would be that entity. But for clarity, it is our belief that the wording in the Functional Model and in the standards is out of step with the reality of present circumstances and that with software being robust and as practical as possible 100 percent available, there is no need for an IA in the FM or Standards.
Response: The CI SARDT acknowledges that WECC can register as the Western Interconnection IA. The NERC Compliance Group has started registering the IAs. The Functional Model and the IA registration are outside the scope of the SAR and standard development. The CI SARDT has attempted to frame the IA issue in the SAR "Purpose" and "Industry Need" in order for the SDT to draft the standards. The goal is to make the standards less ambiguous and more crisp and clear.	
FirstEnergy	FE has the following additional comments: 1. The SAR proposes to, "Consider requiring the Sink Balancing Authority responsibility for Interchange Authority

Organization	Question 6:
	functions, using an interchange transaction tool process as defined in the latest approved version of the E-Tag Specifications." The rules applied to this tool through the E-Tag Specifications are mostly designed to facilitate the application of Transmission Transaction market rules (many of the transmission transaction market rules ultimately facilitate the energy transactions market) which for the most part support the transmission and energy markets and are not applicable to improving reliability. We suggest a revision to the SAR to point only to the parts of the specifications related to reliability and not just include the E-Tag Specifications as a whole. Also, the E-Tag tool is similar to an EMS system in that it is a tool that is used to provide and promote BES reliability. These standards should be no more invasive then the requirements on network analysis or similar systems contained in an EMS tool. 2. Coordination with other projects and SDTs:- The SAR should indicate some type of coordination with the CIP SDT since the CIP-002 through CIP-009 places requirements on the Interchange Authority. The CIP standards will also need to point to the correct owner, operator or user of the BES for the Interchange functions.- NERC Project 2007-14 is in the process of revising INT-005-2, INT-006-2, and INT-008-2. The INT SDT will need to be aware of the latest versions of these standards when they revise all of the INT standards. 3. Definitions - The SAR should also include a review of the current NERC Glossary terms related to interchange to determine if any revisions or new definitions are necessary as a result of the interchange standards development. 4. The SAR indicates "The work in this project should be done in two phases, with the first phase focused solely on clarifying the applicability of each requirement in the existing set of standards. All other revisions should take place in a second phase." FE questions the feasibility of re-assigning the applicability of existing requirements to other NERC Functional Model responsible entities without the ability to concurrently modify requirements to better reflect the real-world interchange transaction process. This concern seems to be supported by the SARs earlier claim that: a) the Interchange Authority function as defined by the Functional Model does not represent technological advances since the FMWG originally defined the IA function b) A potential need for requirement references to the E-Tagging process that is presently in practice within industry. 5. FE agrees with the SAR purpose indicating that "Revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange; ... " In FE's comments to the FMWG related to proposed FM Ver 4 we indicated "The

Organization	Question 6:
	FMWG should give consideration to removing the IA from the FM. The IA Tasks should be re-oriented as needed to the TSP and/or BA entities. The IA does not appear to be a self evident entity to the extent that registration to the IA function will occur. The IDC should be viewed as a tool, not a Functional Model entity, used by the TSP and/or BA to accomplish the described tasks." To this end, we believe the SAR should indicate that the SDT, being comprised of subject matter experts and having reviewed and assessed comments, opinions from a variety of industry stakeholders will at the conclusion of the project provide its recommendation to the FMWG related to the on-going need of the IA functional entity classification.
Response: Thank you for your comments. The CI SARDT responses are: 1. The CI SARDT has attempted to frame the IA issue in the SAR "Purpose" and "Industry Need" in order for the SDT to draft the standards. The goal is to make the standards less ambiguous and more crisp and clear. 2. The CI SARDT appreciates this comment as you brought to the CI SARDT attention that certain INT standards are bbeing reviewed and possibly enhanced. If there are no tasks assigned to the Interchange Authority function, then the SDT will make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity. This statement has been added to the SAR "Brief Description" and to the "Detailed Description." 3. The CI SARDT concurs. Your comment was placed in the SAR "Industry Need." 4. The Purpose statement "Revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange;" is a global Purpose. However, the significant entity that this purpose statement refers to is the IA. The CI SARDT has attempted to frame the IA issue in the SAR "Purpose" and "Industry Need" in order for the SDT to draft the standards. The goal is to make the standards less ambiguous and more crisp and clear. 5. The development of the INT standards will have numerous postings and comment opportunities. Rather than incorporate a SDT requirement to justify their course of action, the CI SARDT recommends that you make a similar comment to future postings, to address your concerns.	
PPL EnergyPlus	(i) INT-001-3 Interchange Transaction Tagging Applicability :Reliability Coordinators need to be included because curtailments of dynamic schedules (covered under INT-004-2) will help reduce unscheduled flow and the RC is responsible to be sure that the data on the tag is enough to assure the right tags get curtailed (i.e. zone data, etc.). The Transmission Service Provider may also need to be included because this same logic may apply to conditional firm curtailments.R2.2: The west uses automatic time-error correction which pays inadvertent back continuously. The magnitude is usually a % of L10 and does not take manual intervention so it might be hard to tag. Should there be an exemption under R2.2 for the WECC time error correction?INT-003-2 Interchange Transaction ImplementationR1: it looks like "net" interchange was inserted then removed. Net is probably useful in this requirement.R1.1: The word RAMP may be useful to have in this section as the sending/receiving BA's must agree on RAMP details.INT-004-2 Interchange Transaction Modifications. It is interesting to note that dynamic schedule tags must be modified if the reserved capacity isn't being fully utilized or more transfer capability is needed (since +/- 10% and +/- 25 MWH covers both more and less than reserved amount). How

Organization	Question 6:
	(practically) will the dynamic schedule get more capacity that reserved? Does this standard need to link to the MOD-001 standard for calculating ATC? It doesn't appear that dynamic schedules deserve any higher priority than any other TSR. Should there be no allowance to exceed reserved capacity (i.e. +0%, -10%) (ii) Pre-R1: Do dynamic schedule curtailments need to be addressed in this standard? (iii) R2.3: The word "deadband" may be useful here to state an amount beyond which the tag must be modified.INT-005-2 Interchange Authority Distributes Arranged Interchange. This standard only addresses curtailments; does another standard address initiating an emergency tags (as when calling on reserves or starting a quick-start unit, etc.). R1.1: Distribute to all BA's on tag, not just source and sink BA's, otherwise losses supplied by intermediary BA's will cause inadvertent for the intermediary BAs. INT-006-2 response to Interchange Authority. No Comments. INT-007-1 Interchange Confirmation. No Comments. INT-008-2 Interchange Authority Distributes Status. No Comments. INT-009-1 Implementation of Interchange. No Comments
Response: The CI SARDT thanks you for your comments. (i) The CI SARDT appreciates your detailed comments. The CI SARDT has attempted to frame the SAR so the SDT can draft the standards. The SAR is at a higher level than your comments. The CI SARDT encourages you to track the progress of the SDT to ensure your concerns are addressed. The CI SARDT does not believe that the SAR needs to link to the MOD-001 standard. (ii) Yes, the CI SARDT concurs with your comment. "Dynamic Schedule Curtailment" was added to the "Industry Need." (iii) The CI SARDT has attempted to frame the SAR in order for the SDT to draft the standards. The SAR is at a higher level than your comments. The CI SARDT encourages you to track the progress of the SDT to ensure your concerns are addressed. The CI SARDT does not believe that the SAR needs to link to the MOD-001 standard.	
WECC	(i) Due to the large volume of transaction requests which must be processed, timely communication, assessment, approval and implementation of Interchange requires some type of software or automated process. SAR should ensure standards do not assume or require 100% availability of these systems for compliant operation should address the impact of a failure or malfunction of software or communication systems, and possibly include alternate standard requirements that would allow for reliable and compliant operation during short duration software or communication failures. (ii) INT Standards should recognize that implementation of transactions (or failure to implement transactions) needed for immediate system reliability such as curtailments, reloads, emergency assistance and deployment of contingency reserves. have a greater reliability impact than routine commercial transactions, particularly forward transactions or market adjustments. This should be considered when establishing standard requirements and violation severity levels for non-compliance.
Response: Thank you for your comments. The CI SARDT responses are:	

Organization	Question 6:
(i) The CI SARDT concurs with your comment. However, the SAR is at a higher level of detail than your comment. The CI SARDT suggests that you track the progress of the standard development and submit your comments to the SDT in the future. **(ii)** "Defining the communications on reloading interchange transactions due to different operational conditions" has been added to the SAR "Purpose" section. TLR curtailments are addressed in IRO-006 and are outside the scope of this SAR and will not be addressed in this SAR.	
PacifiCorp	None at this time.
Tennessee Valley Authority	
CAISO	
SERC OC Standards Review Group	
Ameren	
We Energies	

Standard Authorization Request Form

Title of Proposed Standard	Modifications to Coordinate Interchange Standards for Applicability and General Upgrade
Request Date	May 27, 2008
Modified Date	December 1, 2008

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Interchange Subcommittee	☐	New Standard
Primary Contact Don Lacen, IS Chair	☒	Revision to existing Standards INT-001-2 — Interchange Transaction Tagging INT-003-2 — Interchange Transaction Implementation INT-004-1 — Interchange Transaction Modifications INT-005-2 — Interchange Authority Distributes Arranged Interchange INT-006-2 — Response to Interchange Authority INT-007-1 — Interchange Confirmation INT-008-2 — Interchange Authority Distributes Status INT-009-1 — Implementation of Interchange INT-010-1 — Interchange Coordination Exemptions
Telephone 505-241-2032 Fax 505-241-2582	☐	Withdrawal of existing Standard
E-maildon.lacen@pnm.com	☐	Urgent Action

Purpose **(Describe the proposed standard action: Nomination of a proposed standard, revision to a standard, or withdrawal of a standard and describe what the standard action will achieve.)** Revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange; to address the Interchange Subcommittee concerns related to the Dynamic Transfers and Pseudo-ties; to address previously identified stakeholder comments

and applicable directives from Order 693; to define communications on reloading interchange transactions due to different operational conditions; and to bring the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.
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.) There is confusion regarding the Interchange Authority "function". The need for improved clarity became apparent when entities were recently asked to register in the Compliance Registry as "Interchange Authorities" and entities had difficulty determining which entities were performing the Interchange Authority tasks identified in the set of Coordinate Interchange standards. The Interchange Authority activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities. The Coordinate Interchange standards dealing with the Interchange Authority and the current Functional Model representations of the Interchange Authority do not reflect technological advances made since the Functional Model working group originally defined the Interchange authority and advances made since the Coordinate Interchange standards were written. There are different interpretations surrounding the requirements associated with Dynamic Transfers and Pseudo-ties. Adding definitions for the terms used to reference Dynamic Transfers and Pseudo-ties (e.g., Dynamic Schedule, Dynamic Transfer, Pseudo-tie, Dynamic Schedule Curtailment) will add clarity to these requirements. Additional requirements may be needed to address the principles outlined in the Interchange Subcommittee's Principles and Definitions Supporting Dynamic Transfers and Pseudo-ties. (Attachment 2) Review the current NERC Glossary of Terms related to interchange to determine if any revisions or new definitions are necessary as a result of the Interchange standards development. The work in this project should be addressed in at least two phases with a ballot conducted at the end of each phase. The first phase is needed as soon as possible and should focus on the revisions needed to ensure that each requirement is assigned to a user, owner or operator of the bulk power system. All other proposed revisions should be addressed in the second or subsequent phase(s) of the project.
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Specifications.

- The existing requirements are tool-neutral. Consider adding specific references to the e-Tagging process, applications, and tools in the requirements
- Consider adding a requirement to have backup capability for use when the interchange transaction tool fails.
- Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to follow.
- Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factor drafting team. (See Attachment 1)
- Determine if there is industry-wide support for the Interchange Subcommittee's Principles and definition supporting dynamic transfers and pseudo-ties, and if there is support, modify the requirements and add definitions accordingly.
- If there are no tasks assigned to the Interchange Authority function, then make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity.

Make other changes to the standards to bring them into conformance with the latest version of the Reliability Standards Development Procedure, Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

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Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Revise the following set of Coordinate Interchange Standards so that the responsibility for each of the requirements is clearly assigned to an owner, operator or user of the bulk power system, and not to a tool.

INT-001-2 — Interchange Transaction Tagging
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Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to follow.

Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factor drafting team. (See Attachment 1)

Address the principles and definitions proposed by the Interchange Subcommittee in support of dynamic transfers and pseudo-ties. (See Attachment 2)

Make other changes to the standards to bring them into conformance with the latest version of the Reliability Standards Development Procedure, Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

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Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	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 a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	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.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	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
CIP-002-1 through CIP-009-1	If the industry determines that the IA Function is not an "owner, operator or user" of the BES, then the applicability section of these standards should be modified to remove the IA as a responsible entity.

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1

(Issues originally intended for Project 2009-03 – Interchange Information)

INT-001-2 Interchange Information

Directives from FERC Order 693

- Include a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and “non-Order No. 888” transfers.
- Consider Santa Clara’s comments about the applicability of the LSE in the standard as part of the standards development process.

V0 Industry Comments

- R1 - Too stringent
- R1 – Who tags dynamic schedules?
- Load PSE responsibility is new restriction
- Clarify tagging of reserves
- R2.2 – 60 minute time frame questioned
- Question on generation scheduling
- Onerous to BA’s
- More commercial problem than reliability
- Lack of compliance

VRF Comments

- R1, 1.1, 2, 2.1, 2.2 – commercial and administrative

INT-003-2 Interchange Transaction Implementation

Unresolved Directives from FERC Order 693 – none

VRF Comments

- R1, 1.1, 1.1.2, 1.2 – commercial and administrative

INT-004-1 Dynamic Interchange Transaction Modifications

Unresolved Directives from FERC Order 693 – none

V0 Industry Comments

- Replace TSP with TOP
- Need to address tag curtailment
- Suggested non-compliance levels
- Non-compliance based on %
- Use WECC criteria

VRF Comments

- R2, 2.2, 2.3 – commercial and administrative

INT-005-2 Interchange Authority Distributes Arranged Interchange

Unresolved Directives from FERC Order 693 – none

VRF Comment

- R5 – administrative

INT-006-2 Response to Interchange Authority

Directives from FERC Order 693

- Include reliability coordinators and transmission operators as applicable entities.
- Require reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities' necessary transaction modifications before implementation.
- Consider the suggestions made by EEI and TVA and address questions raised by Entergy and Northern Indiana as part of the standard development process.

INT-007-1 Interchange Confirmation

Unresolved Directives from FERC Order 693 – none

VRF Comment

- R1, 1.1, 1.3, 1.3.1, 1.3.2, 1.3.3, 1.3.4, 1.4 – administrative

INT-008-2 Interchange Authority Distributes Status

Directives from FERC Order 693

- Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

VRF Comments

- R1.1.1 & 1.1.2 – commercial and administrative

INT-009-1 Implementation of Interchange

Directives from FERC Order 693

- Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

INT-010-1 Interchange Coordination Exemptions

Directives from FERC Order 693

- Consider Northern Indiana's and ISO-NE's suggestions in the standards development process.

VRF Comments

- R1 & 3 – administrative

Attachment 2 – Interchange Subcommittee's Principles and Definitions for Dynamic Schedules and Pseudo-ties

Dynamic Schedules

A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between balancing areas. A dynamic schedule must not change a balancing area's jurisdiction; that is, the native balancing area continues to exercise operational jurisdiction over, and provides basic balancing area services to, the dynamically scheduled resources.

All dynamic schedules used to assign the control of generation, loads, or resources from one balancing area to another must meet the following requirements:

1. Telemetry

1.1. Appropriate telemetry for a dynamic schedule must be in place and incorporated by all affected balancing areas. Standards requirements associated with this should address appropriateness issues related to accuracy, sampling rate, etc. which would impact reliability. For example, the relationship of BAL-005-1 R10 and BAL-005-1, R16 should be confirmed.

2. Transmission Service

2.1. Prior to implementation of the dynamic schedule of load or generation, it is the obligation of each involved balancing area to ensure that the dynamic schedule is implemented such that the tariff requirements of the applicable transmission provider(s) are met, including applicable ancillary services and provision of losses.
2.2. If transmission service between the source and sink balancing areas is curtailed then the allowable range of the magnitude of the schedules between them, including dynamic schedules, must be curtailed accordingly. Since dynamic schedules are implemented in ACE via telemetry, curtailment of e-Tags associated with dynamic schedules must be complemented with appropriate adjustments to the telemetered values used in ACE to make the curtailment be physically implemented via ACE control action.

3. System Modeling

3.1. Each balancing area must ensure that the dynamic transfer of load or generation through a dynamic schedule is coordinated with the Reliability Coordinator(s) with responsibility over the native, attaining, and contract intermediary balancing areas so that the dynamic schedule can be properly implemented in the system modeling of the affected generation or load, and necessary data provision requirements are met. Coordination must include tagging of the resultant scheduled interchange for use by other transmission providers and balancing areas for system security analysis and calculation of ATC.
3.2. When a dynamic schedule is used to serve load within another balancing area, the balancing area where the load is electrically connected (native balancing area) must include that load in its balancing area load forecast and any subsequent reporting as needed. This is necessary because the system models must adequately capture the projected demand on the system (load forecast), and the projected supply (provided by the electronic tagging system).

4. Dynamic Schedule Coordination and Scheduling

4.1. Although implemented in the ACE via telemetry, implementation of a dynamic schedule for NERC-identified reliability analysis services must be through the use of an interchange transaction between balancing areas. As such, all dynamic schedules must be tagged and implemented in accordance with NERC Standards.

4.2. Energy exchanged between the source, sink, and intermediary balancing areas as a dynamic schedule is the metered or calculated (obtained by the integration of the dynamic schedule signal over the operating hour) energy for the loads and/or resources for the hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.
4.3. The native balancing area must ensure that agreements are in place defining the responsibility for providing applicable ancillary/interconnected operations services.
4.4. The drafting team should consider reliability impacts and draft appropriate standards related to how dynamic schedules are modeled from various perspectives such as level of detail (i.e. degree to which composite representation is allowed such as each generator having dynamic schedule or allowing a composite plant dynamic schedule) and use of block schedules to serve part of a dynamic schedule. In the latter case, although a single telemetered value may be used in the ACE for a load, it can be represented in the e-Tagging by a combination of one or more block schedules for part of the load and a dynamic schedule for the remainder to represent the dynamic nature of a load.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the dynamic schedule on a plan for how the balancing areas will operate during a loss of the dynamic schedule telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.
5.2. The native balancing area, attaining balancing area and intermediary balancing areas shall agree before implementation of the dynamic schedule upon a plan for how the load will be served during abnormal system conditions including periods of time when the transfer path between them is unavailable. The native balancing area, attaining control area and intermediary balancing areas shall also agree before implementation of the dynamic schedule as to how the generation serving the dynamic schedule will respond during abnormal system conditions, including periods of time when the transfer path between them is unavailable.

Pseudo-Ties
Pseudo-ties are often employed to assign generators, loads, or both from the balancing area to which they are physically connected into a balancing area that has effective operational control of them. Thus, pseudo-ties provide for change of balancing area jurisdiction from the native to the attaining balancing area and at the same time make the attaining balancing area provider of balancing area services. This methodology is also referred to as “AGC Interchange” or “Non-Contiguous Pool Tie.” In practice, pseudo-ties may be implemented based upon metered or calculated values. All balancing areas involved account for the power exchange and associated transmission losses as actual interchange between the balancing areas, both in their ACE equations and throughout all of their energy accounting processes.

All pseudo-ties used to assign generation, loads, or resources from the native balancing area to the attaining balancing area must meet the following requirements:
1. Telemetry
1.1. Appropriate telemetry must be in place and incorporated by all affected balancing areas.

2. Transmission Service
2.1. Prior to implementation of the dynamic transfer of load or generation by pseudo-tie, each involved balancing area shall ensure that the pseudo-tie is implemented such that the

tariff requirements of the applicable transmission provider(s), including applicable ancillary services and provision of losses, are met.
2.2. If transmission service between the native and attaining balancing areas is curtailed, then the allowable range of the magnitude of the pseudo-ties between them must be limited accordingly to these constraints. Since pseudo-ties are implemented in ACE via telemetry, appropriate adjustments must be made to the telemetered values used in ACE to make a curtailment be physically implemented via ACE control action.
2.3. Pseudo-ties must be implemented on firm transmission and are subject to curtailment on a pro rata basis with other firm transactions.

3. System Modeling
3.1. The assignment of load or generation into the control response of another balancing area must be appropriately captured in the IDC and security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators. It is the obligation of each balancing area to ensure that the dynamic transfer of load or generation by pseudo-ties is coordinated with the Reliability Coordinator(s) that have responsibility over the native, attaining, and contract intermediary balancing areas so that the pseudo-tie can be properly implemented in the system modeling of the generation or load affected, and necessary data provision requirements are met.
3.2. The attaining balancing area dynamically transferring load into its effective boundaries through a pseudo-tie shall ensure that load forecasts and subsequent balancing area reporting reflect the load incorporated within its balancing area boundaries.
3.3. If the reliability impact of the pseudo-tie cannot be accurately captured in the IDC and the security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators, the parties must implement the dynamic transfer either through use of a dynamic schedule, or through a combined implementation of pseudo-tie and dynamic schedule where the load or generation within the native balancing area is separately modeled in the IDC.
3.4. The drafting team should consider clarifying how pseudo-tie can be used in reliability analysis activities. For example, since they are not physical ties, should they be omitted from being used as part of a defined flowgate and in physical interface calculations yet be included in inadvertent calculations

4. Pseudo-Ties Coordination and Scheduling
4.1. Subsequent to moving load or resources into an attaining balancing area through pseudo-ties, all interchange transactions or other energy transfers to the loads or from the resources must be coordinated by the attaining balancing area.
4.2. The attaining balancing area assumes responsibility for balancing area services required by the assigned loads and/or resources. The attaining balancing area assumes all regulation, contingency reserves, and other balancing area responsibilities for the loads and/or resources in question.
4.3. Energy exchanged between the native and attaining balancing areas by the pseudo-tie method is accounted for by the associated revenue meter reading for the operating hour (if such meter exists at the dynamically assigned resource or load) or energy calculated by integrating the associated telemetered real-time signal over the operating hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie on a plan for how the balancing areas will operate during a loss of the pseudo-tie telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good

value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.
5.2. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie upon a plan for how the load will be served during abnormal system conditions including periods of time when the interconnection between them is lost. The native balancing area, attaining balancing area, and intermediary balancing areas shall also agree before implementation of the pseudo-tie how the entities will respond during abnormal system conditions, including periods of time when the connection between them is unavailable.

Dynamic Transfer Reference Document
The Drafting Team should take the existing Dynamic Transfer Reference Document, update it as necessary to reflect Functional Model terms and any changes necessary as a result of new requirements from the standards drafting resulting from this SAR and submit it for ballot as a formal reference document linked to those standards. This will provide the industry with a formal, official document to provide guidance on the implementation of dynamic transfers covered in the standards.

The Interchange Subcommittee recommends moving INT-001 standard requirement R.1. to a more appropriate INT standard such as INT-001 or INT-003.

Note: In addition to the above requirements, the NERC Glossary of Terms may need to be amended to include the following new or revised definitions:

ATTAINING BALANCING AREA — A balancing area bringing generation or load into its effective control boundaries through dynamic transfer from the Native Balancing area.

DYNAMIC SCHEDULE — A telemetered reading, or value that is updated in real-time and used as a schedule in the AGC/ACE equation of the affected balancing areas and the integration of which is treated as a schedule for interchange accounting purposes. To the extent that no associated energy metering equipment exists, the integration of the telemetered real time signal is used as a scheduled MWh value for interchange accounting purposes.

DYNAMIC TRANSFER — The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to implement a dynamic schedule or pseudo-tie.

INTEGRATION in the context of dynamic schedules and pseudo-ties means the value could be mathematically calculated or determined mechanically with a metering device.

INTERCONNECTED OPERATIONS SERVICE (IOS) — A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected bulk electric systems.

NATIVE BALANCING AREA — A balancing area from which a portion of its physically interconnected generation and/or load is assigned from its effective control boundaries through dynamic transfer to the attaining balancing area.

PSEUDO-TIE — A telemetered reading, or value that is updated in real time, representative of generation or load assigned dynamically between balancing areas and used as a tie line flow in the affected balancing areas' AGC/ACE equation, but for which no physical balancing area tie actually exists. To the extent that no associated energy metering equipment exists,

the integration of the telemetered real time signal is used as a metered MWh value for interchange accounting purposes.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard	Modifications to Coordinate Interchange Standards for Applicability and General Upgrade
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☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	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 a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	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.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Deleted: ☒

Deleted: ☐

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
CIP-002-1 through CIP-009-1	If the industry determines that the IA Function is not an “owner, operator or user” of the BES, then the applicability section of these standards should be modified to remove the IA as a responsible entity.

Deleted:

Deleted:

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1

(Issues originally intended for Project 2009-03 – Interchange Information)

INT-001-2 Interchange Information

Directives from FERC Order 693

- Include a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.
- Consider Santa Clara's comments about the applicability of the LSE in the standard as part of the standards development process.

V0 Industry Comments

- R1 - Too stringent
- R1 – Who tags dynamic schedules?
- Load PSE responsibility is new restriction
- Clarify tagging of reserves
- R2.2 – 60 minute time frame questioned
- Question on generation scheduling
- Onerous to BA's
- More commercial problem than reliability
- Lack of compliance

VRF Comments

- R1, 1.1, 2, 2.1, 2.2 – commercial and administrative

INT-003-2 Interchange Transaction Implementation

Unresolved Directives from FERC Order 693 – none

VRF Comments

- R1, 1.1, 1.1.2, 1.2 – commercial and administrative

INT-004-1 Dynamic Interchange Transaction Modifications

Unresolved Directives from FERC Order 693 – none

V0 Industry Comments

- Replace TSP with TOP
- Need to address tag curtailment
- Suggested non-compliance levels
- Non-compliance based on %
- Use WECC criteria

VRF Comments

- R2, 2.2, 2.3 – commercial and administrative

INT-005-2 Interchange Authority Distributes Arranged Interchange

Unresolved Directives from FERC Order 693 – none

VRF Comment

- R5 – administrative

INT-006-2 Response to Interchange Authority

Directives from FERC Order 693

- Include reliability coordinators and transmission operators as applicable entities.
- Require reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities' necessary transaction modifications before implementation.
- Consider the suggestions made by EEI and TVA and address questions raised by Entergy and Northern Indiana as part of the standard development process.

INT-007-1 Interchange Confirmation

Unresolved Directives from FERC Order 693 – none

VRF Comment

- R1, 1.1, 1.3, 1.3.1, 1.3.2, 1.3.3, 1.3.4, 1.4 – administrative

INT-008-2 Interchange Authority Distributes Status

Directives from FERC Order 693

- Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

VRF Comments

- R1.1.1 & 1.1.2 – commercial and administrative

INT-009-1 Implementation of Interchange

Directives from FERC Order 693

- Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

INT-010-1 Interchange Coordination Exemptions

Directives from FERC Order 693

- Consider Northern Indiana's and ISO-NE's suggestions in the standards development process.

VRF Comments

- R1 & 3 – administrative

Attachment 2 – Interchange Subcommittee's Principles and Definitions for Dynamic Schedules and Pseudo-ties

Dynamic Schedules

A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between balancing areas. A dynamic schedule must not change a balancing area's jurisdiction; that is, the native balancing area continues to exercise operational jurisdiction over, and provides basic balancing area services to, the dynamically scheduled resources.

All dynamic schedules used to assign the control of generation, loads, or resources from one balancing area to another must meet the following requirements:

1. Telemetry

1.1. Appropriate telemetry for a dynamic schedule must be in place and incorporated by all affected balancing areas. Standards requirements associated with this should address appropriateness issues related to accuracy, sampling rate, etc. which would impact reliability. For example, the relationship of BAL-005-1 R10 and BAL-005-1, R16 should be confirmed.

2. Transmission Service

2.1. Prior to implementation of the dynamic schedule of load or generation, it is the obligation of each involved balancing area to ensure that the dynamic schedule is implemented such that the tariff requirements of the applicable transmission provider(s) are met, including applicable ancillary services and provision of losses.

2.2. If transmission service between the source and sink balancing areas is curtailed then the allowable range of the magnitude of the schedules between them, including dynamic schedules, must be curtailed accordingly. Since dynamic schedules are implemented in ACE via telemetry, curtailment of e-Tags associated with dynamic schedules must be complemented with appropriate adjustments to the telemetered values used in ACE to make the curtailment be physically implemented via ACE control action.

3. System Modeling

3.1. Each balancing area must ensure that the dynamic transfer of load or generation through a dynamic schedule is coordinated with the Reliability Coordinator(s) with responsibility over the native, attaining, and contract intermediary balancing areas so that the dynamic schedule can be properly implemented in the system modeling of the affected generation or load, and necessary data provision requirements are met. Coordination must include tagging of the resultant scheduled interchange for use by other transmission providers and balancing areas for system security analysis and calculation of ATC.

3.2. When a dynamic schedule is used to serve load within another balancing area, the balancing area where the load is electrically connected (native balancing area) must include that load in its balancing area load forecast and any subsequent reporting as needed. This is necessary because the system models must adequately capture the projected demand on the system (load forecast), and the projected supply (provided by the electronic tagging system).

4. Dynamic Schedule Coordination and Scheduling

4.1. Although implemented in the ACE via telemetry, implementation of a dynamic schedule for NERC-identified reliability analysis services must be through the use of an interchange transaction between balancing areas. As such, all dynamic schedules must be tagged and implemented in accordance with NERC Standards.

4.2. Energy exchanged between the source, sink, and intermediary balancing areas as a dynamic schedule is the metered or calculated (obtained by the integration of the dynamic schedule signal over the operating hour) energy for the loads and/or resources for the hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.
4.3. The native balancing area must ensure that agreements are in place defining the responsibility for providing applicable ancillary/interconnected operations services.
4.4. The drafting team should consider reliability impacts and draft appropriate standards related to how dynamic schedules are modeled from various perspectives such as level of detail (i.e. degree to which composite representation is allowed such as each generator having dynamic schedule or allowing a composite plant dynamic schedule) and use of block schedules to serve part of a dynamic schedule. In the latter case, although a single telemetered value may be used in the ACE for a load, it can be represented in the e-Tagging by a combination of one or more block schedules for part of the load and a dynamic schedule for the remainder to represent the dynamic nature of a load.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the dynamic schedule on a plan for how the balancing areas will operate during a loss of the dynamic schedule telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.
5.2. The native balancing area, attaining balancing area and intermediary balancing areas shall agree before implementation of the dynamic schedule upon a plan for how the load will be served during abnormal system conditions including periods of time when the transfer path between them is unavailable. The native balancing area, attaining control area and intermediary balancing areas shall also agree before implementation of the dynamic schedule as to how the generation serving the dynamic schedule will respond during abnormal system conditions, including periods of time when the transfer path between them is unavailable.

Pseudo-Ties
Pseudo-ties are often employed to assign generators, loads, or both from the balancing area to which they are physically connected into a balancing area that has effective operational control of them. Thus, pseudo-ties provide for change of balancing area jurisdiction from the native to the attaining balancing area and at the same time make the attaining balancing area provider of balancing area services. This methodology is also referred to as “AGC Interchange” or “Non-Contiguous Pool Tie.” In practice, pseudo-ties may be implemented based upon metered or calculated values. All balancing areas involved account for the power exchange and associated transmission losses as actual interchange between the balancing areas, both in their ACE equations and throughout all of their energy accounting processes.

All pseudo-ties used to assign generation, loads, or resources from the native balancing area to the attaining balancing area must meet the following requirements:
1. Telemetry
1.1. Appropriate telemetry must be in place and incorporated by all affected balancing areas.

2. Transmission Service
2.1. Prior to implementation of the dynamic transfer of load or generation by pseudo-tie, each involved balancing area shall ensure that the pseudo-tie is implemented such that the

tariff requirements of the applicable transmission provider(s), including applicable ancillary services and provision of losses, are met.
2.2. If transmission service between the native and attaining balancing areas is curtailed, then the allowable range of the magnitude of the pseudo-ties between them must be limited accordingly to these constraints. Since pseudo-ties are implemented in ACE via telemetry, appropriate adjustments must be made to the telemetered values used in ACE to make a curtailment be physically implemented via ACE control action.
2.3. Pseudo-ties must be implemented on firm transmission and are subject to curtailment on a pro rata basis with other firm transactions.

3. System Modeling
3.1. The assignment of load or generation into the control response of another balancing area must be appropriately captured in the IDC and security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators. It is the obligation of each balancing area to ensure that the dynamic transfer of load or generation by pseudo-ties is coordinated with the Reliability Coordinator(s) that have responsibility over the native, attaining, and contract intermediary balancing areas so that the pseudo-tie can be properly implemented in the system modeling of the generation or load affected, and necessary data provision requirements are met.
3.2. The attaining balancing area dynamically transferring load into its effective boundaries through a pseudo-tie shall ensure that load forecasts and subsequent balancing area reporting reflect the load incorporated within its balancing area boundaries.
3.3. If the reliability impact of the pseudo-tie cannot be accurately captured in the IDC and the security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators, the parties must implement the dynamic transfer either through use of a dynamic schedule, or through a combined implementation of pseudo-tie and dynamic schedule where the load or generation within the native balancing area is separately modeled in the IDC.
3.4. The drafting team should consider clarifying how pseudo-tie can be used in reliability analysis activities. For example, since they are not physical ties, should they be omitted from being used as part of a defined flowgate and in physical interface calculations yet be included in inadvertent calculations

4. Pseudo-Ties Coordination and Scheduling
4.1. Subsequent to moving load or resources into an attaining balancing area through pseudo-ties, all interchange transactions or other energy transfers to the loads or from the resources must be coordinated by the attaining balancing area.
4.2. The attaining balancing area assumes responsibility for balancing area services required by the assigned loads and/or resources. The attaining balancing area assumes all regulation, contingency reserves, and other balancing area responsibilities for the loads and/or resources in question.
4.3. Energy exchanged between the native and attaining balancing areas by the pseudo-tie method is accounted for by the associated revenue meter reading for the operating hour (if such meter exists at the dynamically assigned resource or load) or energy calculated by integrating the associated telemetered real-time signal over the operating hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie on a plan for how the balancing areas will operate during a loss of the pseudo-tie telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good

value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

5.2. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie upon a plan for how the load will be served during abnormal system conditions including periods of time when the interconnection between them is lost. The native balancing area, attaining balancing area, and intermediary balancing areas shall also agree before implementation of the pseudo-tie how the entities will respond during abnormal system conditions, including periods of time when the connection between them is unavailable.

Dynamic Transfer Reference Document

The Drafting Team should take the existing Dynamic Transfer Reference Document, update it as necessary to reflect Functional Model terms and any changes necessary as a result of new requirements from the standards drafting resulting from this SAR and submit it for ballot as a formal reference document linked to those standards. This will provide the industry with a formal, official document to provide guidance on the implementation of dynamic transfers covered in the standards.

The Interchange Subcommittee recommends moving INT-001 standard requirement R.1. to a more appropriate INT standard such as INT-001 or INT-003.

Note: In addition to the above requirements, the NERC Glossary of Terms may need to be amended to include the following new or revised definitions:

ATTAINING BALANCING AREA — A balancing area bringing generation or load into its effective control boundaries through dynamic transfer from the Native Balancing area.

DYNAMIC SCHEDULE — A telemetered reading, or value that is updated in real-time and used as a schedule in the AGC/ACE equation of the affected balancing areas and the integration of which is treated as a schedule for interchange accounting purposes. To the extent that no associated energy metering equipment exists, the integration of the telemetered real time signal is used as a scheduled MWh value for interchange accounting purposes.

DYNAMIC TRANSFER — The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to implement a dynamic schedule or pseudo-tie.

INTEGRATION in the context of dynamic schedules and pseudo-ties means the value could be mathematically calculated or determined mechanically with a metering device.

INTERCONNECTED OPERATIONS SERVICE (IOS) — A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected bulk electric systems.

NATIVE BALANCING AREA — A balancing area from which a portion of its physically interconnected generation and/or load is assigned from its effective control boundaries through dynamic transfer to the attaining balancing area.

PSEUDO-TIE — A telemetered reading, or value that is updated in real time, representative of generation or load assigned dynamically between balancing areas and used as a tie line flow in the affected balancing areas' AGC/ACE equation, but for which no physical balancing area tie actually exists. To the extent that no associated energy metering equipment exists,

the integration of the telemetered real time signal is used as a metered MWh value for interchange accounting purposes.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Nomination Form for CI Revisions Standard Drafting Team (Project 2008-12)

Please submit your nomination via the electronic form located at the site below by **January 16, 2009.**

http://www.nerc.com/filez/standards/Project2008-12_Coordinate_Interchange_Stds_Modifications.html

If you have any questions, please contact David Taylor at david.taylor@nerc.net or by telephone at 609-452-8060 or 609-651-5089.

All candidates should be prepared to participate actively at these meetings.

Name: Organization: Address: Office Telephone: E-mail:	
Please briefly describe your experience and qualifications to serve on the CI Revisions Standard Drafting Team. Prefer experience in managing activities associated with coordinating interchange. Previous experience working on or applying NERC or IEEE standards is beneficial, but not a requirement.	
Are you a member of any NERC SAR or standard drafting team? If yes, please list each team here.	☐ No ☐ Yes:
Have you previously worked on any SAR or standard drafting team? If yes, please list	☐ No ☐ Yes:

<table>
<tr><td>them here.</td><td colspan="2"></td></tr>
<tr><td rowspan="12">I represent the following NERC Reliability Region(s) (check all that apply):
☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☐ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td colspan="2">I represent the following Industry Segments (Check all that apply):</td></tr>
<tr><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs, ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, and Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
<tr><td>☐</td><td>Not applicable</td></tr>
</table>

Which of the following Function(s)[1] do you have expertise or responsibilities:

☐ Balancing Authority	☐ Planning Coordinator
☐ Compliance Enforcement Authority	☐ Transmission Operator
☐ Distribution Provider	☐ Transmission Owner
☐ Generator Operator	☐ Transmission Planner
☐ Generator Owner	☐ Transmission Service Provider
☐ Interchange Authority	☐ Purchasing-selling Entity
☐ Load-serving Entity	☐ Resource Planner
☐ Market Operator	☐ Reliability Coordinator

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.

Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

[1] These functions are defined in the NERC Functional Model, which is downloadable from the NERC Web site.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Nomination Period Opens for Standard Drafting Team
January 5ï16, 2009

Now available at:
http://www.nerc.com/filez/standards/Project2008-12_Coordinate_Interchange_Stds_Modifications.html

Nominations for Standards Drafting Team (Project 2008-12 — Coordinate Interchange Standards)

The Standards Committee is seeking industry experts to serve on the Coordinate Interchange Standards Drafting Team. The drafting team will work to modify the following standards:

INT-001-2 — Interchange Transaction Tagging
INT-003-2 — Interchange Transaction Implementation
INT-004-1 — Interchange Transaction Modifications
INT-005-2 — Interchange Authority Distributes Arranged Interchange
INT-006-2 — Response to Interchange Authority
INT-007-1 — Interchange Confirmation
INT-008-2 — Interchange Authority Distributes Status
INT-009-1 — Implementation of Interchange
INT-010-1 — Interchange Coordination Exemptions

If you are interested in serving on this standard drafting team, please complete the following electronic nomination form **by January 16, 2009**:
https://www.nerc.net/nercsurvey/Survey.aspx?s=e522fac27d5d43c7a5ba25e856e19728.

Please contact Dave Taylor at david.taylor@nerc.net or at 609-651-5089 with any questions about the team.

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.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. Revised SAR and response to comments approved by SC (December 16–17, 2008).
4. SDT appointed on (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR and applicable FERC directives from FERC Order 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to Comments and Post for 45-day stakeholder review.	June-July 2010
2. Respond to Comments and Post for 30-day pre-ballot review.	October 2010
3. Conduct initial ballot.	November 2010
4. Post response to comments on initial ballot.	January 2011
5. Conduct recirculation ballot.	January 2011
6. Submit standard to BOT for adoption.	February 2011
7. File standard with regulatory authorities.	March 2011.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Dynamic Schedules**

2. **Number:** INT-004-3

3. **Purpose:** To ensure Dynamic Schedules are communicated and accounted for appropriately in reliability tools (for example: the NERC Interchange Distribution Calculator (IDC), the WECC Security Analysis System (SAS)).

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Reliability Coordinators

   4.3. Transmission Operators

   4.4. Purchasing-Selling Entities

5. **Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities or, in those jurisdictions where regulatory approval is not required the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. The Load-serving, Purchasing-Selling Entity associated with a Dynamic Schedule shall [1]ensure that a Request for Interchange is submitted as an On-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule at either

- The expected average MW profile for each hour if a forecast for the Dynamic Schedule is available, or
- The expected maximum MW profile for each hour if no forecast is available for the Dynamic Schedule.

R2. The Purchasing-Selling Entity that submits a Request for Interchange for a Dynamic Schedule shall[2] ensure the Confirmed Interchange associated with that Dynamic Schedule is updated for the next available scheduling hour and future hours when any one of the following occurs:

R2.1. For Confirmed Interchange using the expected average MW profile, when the average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated in the Confirmed Interchange by more than $\pm$10%.

[1] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[2] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

R2.2. For Confirmed Interchange using the expected average MW profile, when the average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated in the Confirmed Interchange by more than $\pm$25 megawatt-hours.

R2.3. A Reliability Coordinator or Transmission Operator determines the deviation from the hourly energy profile indicated in the Confirmed Interchange, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of the reliability concerns.

C. Measures

M1. TBD.

D. Compliance

1. **TBD**

E. Regional Differences

1. None

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Board of Trustees Approval	Revised
2	October 9, 2007	Board of Trustees Approval (Removal of WECC Waiver)	Revised
2	July 21, 2008	FERC Approval	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Dynamic ~~Interchange Transaction Modifications~~Schedules**

2. **Number:** INT-004-~~2~~3

3. **Purpose:** To ensure Dynamic ~~Transfers~~Schedules are ~~adequately tagged to be able to determine their~~communicated and accounted for appropriately in reliability ~~impacts~~tools (for example: the NERC Interchange Distribution Calculator (IDC), the WECC Security Analysis System (SAS)).

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Reliability Coordinators

   4.3. Transmission Operators

   4.4. Purchasing-Selling Entities

~~5.~~ **Effective Date:** ~~August 27, 2008 (U.S.)~~

5. First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities~~,~~ or, in those jurisdictions where regulatory approval is not required~~,~~ the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board ~~Approval: October 9, 2007~~of Trustees.

B. Requirements

~~**R2.** At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.~~

R1. The Load-serving, Purchasing-Selling Entity ~~responsible for tagging~~associated with a Dynamic ~~Interchange~~ Schedule shall [1]ensure that a Request for Interchange is submitted as an On-time Arranged Interchange to the ~~tag~~Sink Balancing Authority for that Dynamic Schedule at either

- The expected average MW profile for each hour if a forecast for the Dynamic Schedule is available, or
- The expected maximum MW profile for each hour if no forecast is available for the Dynamic Schedule.

[IC1]

[1] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

R2. The Purchasing-Selling Entity that submits a Request for Interchange for a Dynamic Schedule shall[2] ensure the Confirmed Interchange associated with that Dynamic Schedule is updated for the next available scheduling hour and future hours when any one of the following occurs:

R2.1. ~~The~~ For Confirmed Interchange using the expected average MW profile, when the average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated ~~on~~in the ~~tag~~Confirmed Interchange by more than ±10%.

R2.2. ~~The~~ For Confirmed Interchange using the expected average MW profile, when the average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated ~~on~~in the ~~tag~~Confirmed Interchange by more than ±25 megawatt-hours.

R2.3. A Reliability Coordinator or Transmission Operator determines the deviation from the hourly energy profile indicated in the Confirmed Interchange, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of ~~that determination and the reasons~~the reliability concerns.

C. Measures

M1. TBD.

D. Compliance

1. **TBD**

E. Regional Differences

1. None

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Board of Trustees Approval	Revised
2	October 9, 2007	Board of Trustees Approval (Removal of WECC Waiver)	Revised
2	July 21, 2008	FERC Approval	Revised

[2] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. Revised SAR and response to comments approved by SC (December 16–17, 2008).
4. SDT appointed on (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR and applicable FERC directives from FERC Order 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to Comments and Post for 45-day stakeholder review.	June-July 2010
2. Respond to Comments and Post for 30-day pre-ballot review.	October 2010
3. Conduct initial ballot.	November 2010
4. Post response to comments on initial ballot.	January 2011
5. Conduct recirculation ballot.	January 2011
6. Submit standard to BOT for adoption.	February 2011
7. File standard with regulatory authorities.	March 2011.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Evaluation of Interchange Transactions**

2. **Number:** INT-006-4

3. **Purpose:** To ensure that each Arranged Interchange is checked for reliability before it is implemented.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Service Provider

   4.3. Reliability Coordinator

   4.4. Transmission Operator

5. **Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Sink Balancing Authority shall[1] distribute each Arranged Interchange to the Source Balancing Authority, each Intermediate Balancing Authority, each Reliability Coordinator, and each Transmission Service Provider included in the Arranged Interchange less than one minute after receipt of any associated Request for Interchange or requested modifications to Confirmed or Implemented Interchange that meets all of the following criteria:

1.1. The Request for Interchange or requested modification to Confirmed or Implemented Interchange was received by the Sink Balancing Authority on-time, and

1.2. The Arranged Interchange was not transitioned to Confirmed Interchange, and

1.3. Notification of the Arranged Interchange being transitioned to Confirmed Interchange was distributed less than three minutes prior to the requested ramp start, and

1.4. The Arranged Interchange was not denied by any approval entity.

R2. Each Balancing Authority receiving an On-time Arranged Interchange or an emergency Arranged Interchange from a Sink Balancing Authority, shall[2] approve or deny its transition to Confirmed Interchange prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, Column B,[3]

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[1] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[2] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[3] Balancing Authorities need not provide responses to any other requests.

2.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange if 1.) it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange, and/or 2.) the scheduling path (proper connectivity of Adjacent Balancing Authorities) is invalid.

R3. Each Transmission Service Provider receiving an On-time Arranged Interchange or an emergency Arranged Interchange from a Sink Balancing Authority, shall[4] approve or deny its transition to Confirmed Interchange prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, column B[5].

3.1. Transmission Service Providers shall deny the Arranged Interchange if 1.) the unscheduled capacity remaining for the Transmission Service Request (or other contractual/tariff arrangement) on the Transmission Providers system will not accommodate the Arranged Interchange, 2.) the Transmission system does not have the capability to accommodate the Arranged Interchange based on projected system conditions, or 3.) the transmission path (proper connectivity of adjacent Transmission Service Providers) is invalid.

R4. Each Source Balancing Authority, Sink Balancing Authority, and Balancing Authority associated with a direct-current tie operator receiving a Reliability Adjustment Request for Interchange shall[6] approve the Reliability Adjustment Request for Interchange prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, column B, if it can support the magnitude of the Interchange, including ramping, throughout the duration of the Reliability Adjustment Request for Interchange.

R5. Each Sink Balancing Authority shall[7] transition Arranged Interchange to Confirmed Interchange if any of the following conditions are met:

5.1. All entities associated with the Arranged Interchange have communicated their approval of the transition

5.2. The Arranged Interchange represents a Reliability Adjustment and the Source Balancing Authority, direct-current tie Operating Balancing Authority, and the Sink Balancing Authority associated with the Arranged Interchange have communicated their approval of the transition

5.3. The time period specified in Attachment 1, column B, has elapsed, all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transitions, and no other entities associated with the Arranged Interchange have communicated their denial of the transition.

R6. Each Sink Balancing Authority shall[8] not transition an Arranged Interchange to Confirmed Interchange if any of the following conditions are met:

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[4] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[5] Transmission Service Providers need not provide responses to any other requests.

[6] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[7] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

6.1. The Arranged Interchange represents a Reliability Adjustment; the time period specified in Attachment 1, column B, has elapsed; and one or more of the following entities associated with the Arranged Interchange have not communicated their approval of the transition: the Source Balancing Authority, the direct-current tie Operating Balancing Authority, or the Sink Balancing Authority.

6.2. The Arranged Interchange does not represent a Reliability Adjustment; the time period specified in Attachment 1, column B, has elapsed; and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition

6.3. The Arranged Interchange does not represent a Reliability Adjustment, the time period specified in Attachment 1, column B, has elapsed, and any entity associated with the Arranged Interchange has communicated their denial of the transition

R7. Each Sink Balancing Authority shall[9] distribute all notifications of whether or not Arranged Interchange was transitioned to Confirmed Interchange to the Source Balancing Authority, each Intermediate Balancing Authority, each Reliability Coordinator, and each Transmission Service Provider included in the Arranged Interchange less than one minute after making the decision to transition or not for any Arranged Interchange that meets all of the following criteria:

7.1. The Request for Interchange or requested modification to Confirmed or Implemented Interchange was received by the Sink Balancing Authority on-time, and

7.2. Notification of whether or not the Arranged Interchange was transitioned to Confirmed Interchange was not distributed three or more minutes prior to the requested ramp start, and

7.3. Not all entities actively responded during the reliability assessment period defined in the timing requirements in Attachment 1, column B, and

7.4. The Arranged Interchange was not denied by any approval entity.

R8. On a day-ahead basis, each Transmission Operator shall notify the associated Sink Balancing Authority(ies) of any Interchange modifications potentially required to mitigate any previously identified expected SOL or IROL exceedances.

R9. On a day-ahead basis, each Reliability Coordinator shall notify the associated Sink Balancing Authority(ies) of any Interchange modifications potentially required to mitigate any previously identified expected IROL exceedances.

C. Measures

M1. TBD

D. Compliance

1. TBD

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[8] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[9] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

E. Regional Differences

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised

Timing Requirements for all Interconnections except WECC

Request for Interchange Submitted

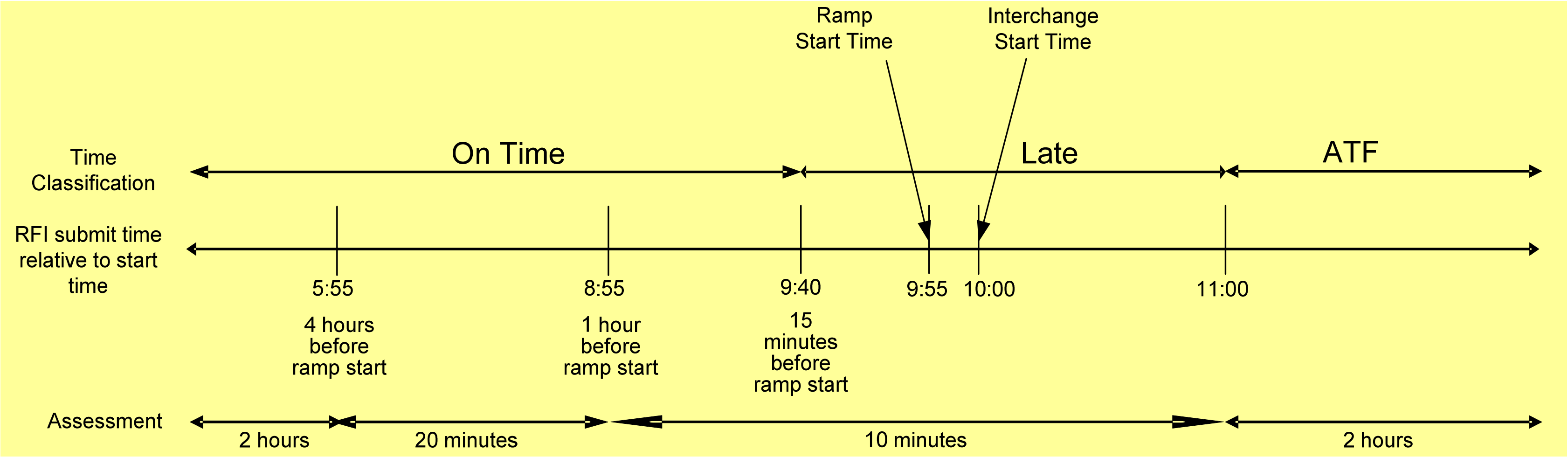
Interchange Timeline with Minimum Reliability-Related Response Times

Ramp Start

		A	B	C	D
If Arranged Interchange (RFI)[10] is Submitted	**Assigned Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**Sink BA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the RFI start time	ATF	≤ 1 minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
<15 minutes prior to ramp start and ≤1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[10] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC

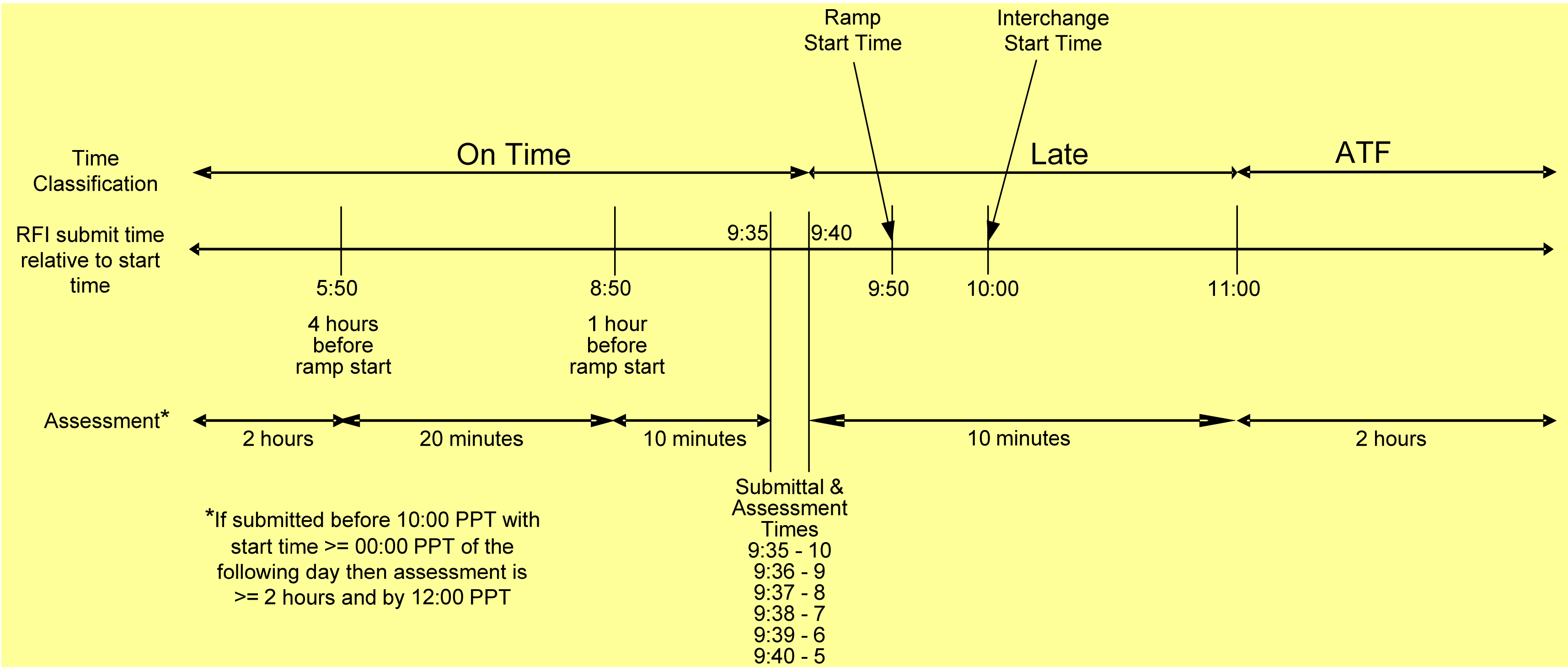


Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange (RFI)[11] is Submitted	**Assigned Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**Sink BA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
10 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 6 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
12 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 7 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 8 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 9 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1hour and < 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	< 20 minutes from Arranged interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time	≤ 1minute from RFI submission	By 12:00 PPT of day the Arranged Interchange was received by the IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

11 Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC



Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. Revised SAR and response to comments approved by SC (December 16–17, 2008).
4. SDT appointed on (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard posted for stakeholder comments. This draft includes the modifications identified in the SAR and applicable FERC directives from FERC Order 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to Comments and Post for 45-day stakeholder review.	June-July 2010
2. Respond to Comments and Post for 30-day pre-ballot review.	October 2010
3. Conduct initial ballot.	November 2010
4. Post response to comments on initial ballot.	January 2011
5. Conduct recirculation ballot.	January 2011
6. Submit standard to BOT for adoption.	February 2011
7. File standard with regulatory authorities.	March 2011.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

~~1.~~**Title:** ~~Response to~~ Evaluation of Interchange ~~Authority~~

1. **Transactions**
2. **Number:** INT-006-~~3~~4
3. **Purpose:** To ensure that each Arranged Interchange is checked for reliability before it is implemented.
4. **Applicability:**
   - **4.1.** Balancing Authority.
   - **4.2.** Transmission Service Provider.
   - **4.3.** Reliability Coordinator
   - **4.4.** Transmission Operator
5. **Effective Date:** ~~The~~ First day of the first calendar quarter following the date this standard ~~shall become~~is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter~~, three months~~ after ~~all regulatory approvals.~~the date this standard is approved by the NERC Board of Trustees.

B. Requirements

~~**R1.** Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.~~[1]

~~**1.1.** Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:~~

~~**1.1.1.** Energy profile (ability to support the magnitude of the Interchange).~~

~~**1.1.2.** Ramp (ability of generation maneuverability to accommodate).~~

~~**1.1.3.** Scheduling path (proper connectivity of Adjacent Balancing Authorities).~~

~~**1.2.** Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated.~~

R1. Each Sink Balancing Authority shall[2] distribute each Arranged Interchange to the Source Balancing Authority, each Intermediate Balancing Authority, each Reliability Coordinator, and each Transmission Service Provider included in the Arranged Interchange less than one minute

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~~[1] The Balancing Authority and Transmission Service Provider need not provide responses to any other requests.~~

[2] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

after receipt of any associated Request for Interchange or requested modifications to Confirmed or Implemented Interchange that meets all of the following criteria:

1.1. The Request for Interchange or requested modification to Confirmed or Implemented Interchange was received by the Sink Balancing Authority on-time, and

1.2. The Arranged Interchange was not transitioned to Confirmed Interchange, and

1.3. Notification of the Arranged Interchange being transitioned to Confirmed Interchange was distributed less than three minutes prior to the requested ramp start, and

1.4. The Arranged Interchange was not denied by any approval entity.

R2. Each Balancing Authority receiving an On-time Arranged Interchange or an emergency Arranged Interchange from a Sink Balancing Authority, shall[3] approve or deny its transition to Confirmed Interchange [IC1]prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, Column B,[4]

2.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange if 1.) it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange, and/or 2.) the scheduling path (proper connectivity of Adjacent Balancing Authorities) is invalid.

R3. Each Transmission Service Provider receiving an On-time Arranged Interchange or an emergency Arranged Interchange from a Sink Balancing Authority, shall[5] approve or deny its transition to Confirmed Interchange prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, column B[6].

3.1. Transmission Service Providers shall deny the Arranged Interchange if 1.) the unscheduled capacity remaining for the Transmission Service Request (or other contractual/tariff arrangement) on the Transmission Providers system will not accommodate the Arranged Interchange, 2.) the Transmission system does not have the capability to accommodate the Arranged Interchange based on projected system conditions, or 3.) the transmission path (proper connectivity of adjacent Transmission Service Providers) is invalid.

R4. Each Source Balancing Authority, Sink Balancing Authority, and Balancing Authority associated with a direct-current tie operator receiving a Reliability Adjustment Request for Interchange shall[7] approve the Reliability Adjustment Request for Interchange prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment

[3] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[4] Balancing Authorities need not provide responses to any other requests.

[5] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[6] Transmission Service Providers need not provide responses to any other requests.

[7] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

1, column B, if it can support the magnitude of the Interchange, including ramping, throughout the duration of the Reliability Adjustment Request for Interchange.

R5. Each Sink Balancing Authority shall[8] transition Arranged Interchange to Confirmed Interchange if any of the following conditions are met:

5.1. All entities associated with the Arranged Interchange have communicated their approval of the transition

5.2. The Arranged Interchange represents a Reliability Adjustment and the Source Balancing Authority, direct-current tie Operating Balancing Authority, and the Sink Balancing Authority associated with the Arranged Interchange have communicated their approval of the transition

5.3. The time period specified in Attachment 1, column B, has elapsed, all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transitions, and no other entities associated with the Arranged Interchange have communicated their denial of the transition.

R6. Each Sink Balancing Authority shall[9] not transition an Arranged Interchange to Confirmed Interchange if any of the following conditions are met:

6.1. The Arranged Interchange represents a Reliability Adjustment; the time period specified in Attachment 1, column B, has elapsed; and one or more of the following entities associated with the Arranged Interchange have not communicated their approval of the transition: the Source Balancing Authority, the direct-current tie Operating Balancing Authority, or the Sink Balancing Authority.

6.2. The Arranged Interchange does not represent a Reliability Adjustment; the time period specified in Attachment 1, column B, has elapsed; and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition

6.3. The Arranged Interchange does not represent a Reliability Adjustment, the time period specified in Attachment 1, column B, has elapsed, and any entity associated with the Arranged Interchange has communicated their denial of the transition

R7. Each Sink Balancing Authority shall[10] distribute all notifications of whether or not Arranged Interchange was transitioned to Confirmed Interchange to the Source Balancing Authority, each Intermediate Balancing Authority, each Reliability Coordinator, and each Transmission Service Provider included in the Arranged Interchange less than one minute after making the decision to transition or not for any Arranged Interchange that meets all of the following criteria:

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[8] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[9] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[10] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

7.1. The Request for Interchange or requested modification to Confirmed or Implemented Interchange was received by the Sink Balancing Authority on-time, and

7.2. Notification of whether or not the Arranged Interchange was transitioned to Confirmed Interchange was not distributed three or more minutes prior to the requested ramp start, and

7.3. Not all entities actively responded during the reliability assessment period defined in the timing requirements in Attachment 1, column B, and

7.4. The Arranged Interchange was not denied by any approval entity.

R8. On a day-ahead basis, each Transmission Operator shall notify the associated Sink Balancing Authority(ies) of any Interchange modifications potentially required to mitigate any previously identified expected SOL or IROL exceedances.

R9. On a day-ahead basis, each Reliability Coordinator shall notify the associated Sink Balancing Authority(ies) of any Interchange modifications potentially required to mitigate any previously identified expected IROL exceedances.

C. Measures

M1. TBD

D. Compliance

1. TBD

E. Regional Differences

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised

Timing Requirements for all Interconnections except WECC

Request for Interchange Submitted

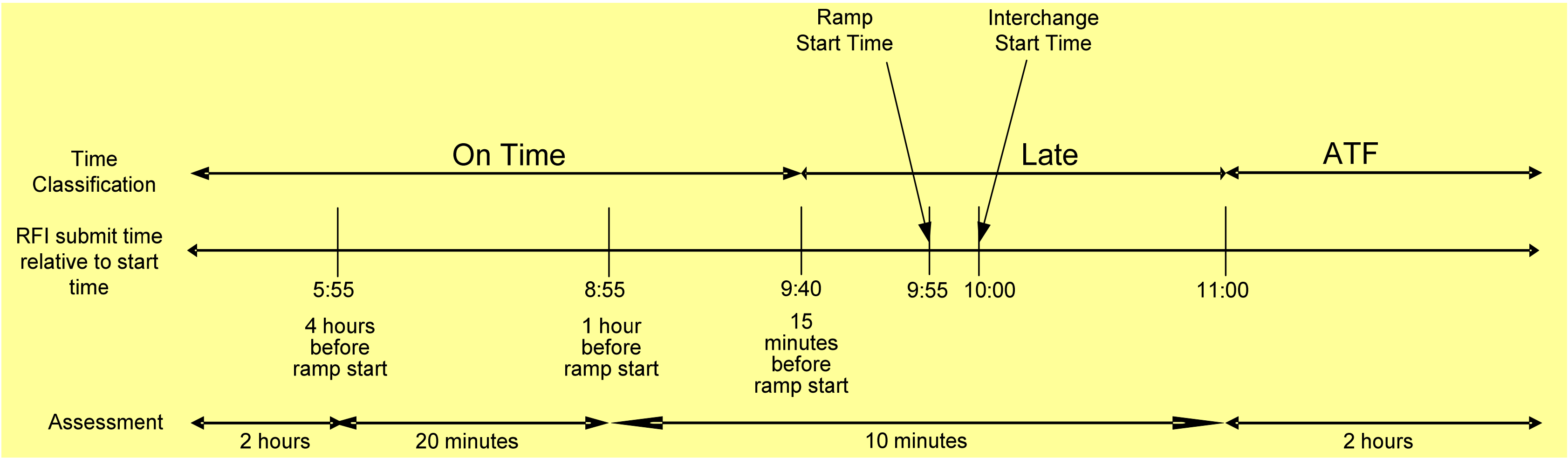
Interchange Timeline with Minimum Reliability-Related Response Times

Ramp Start

		A	B	C	D
If Arranged Interchange (RFI)[11] is Submitted	**~~IA~~ Assigned Time Classification**	**~~IA~~Sink BA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**~~IA~~Sink BA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the RFI start time	ATF	≤ 1 minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
<15 minutes prior to ramp start and ≤1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[11] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC

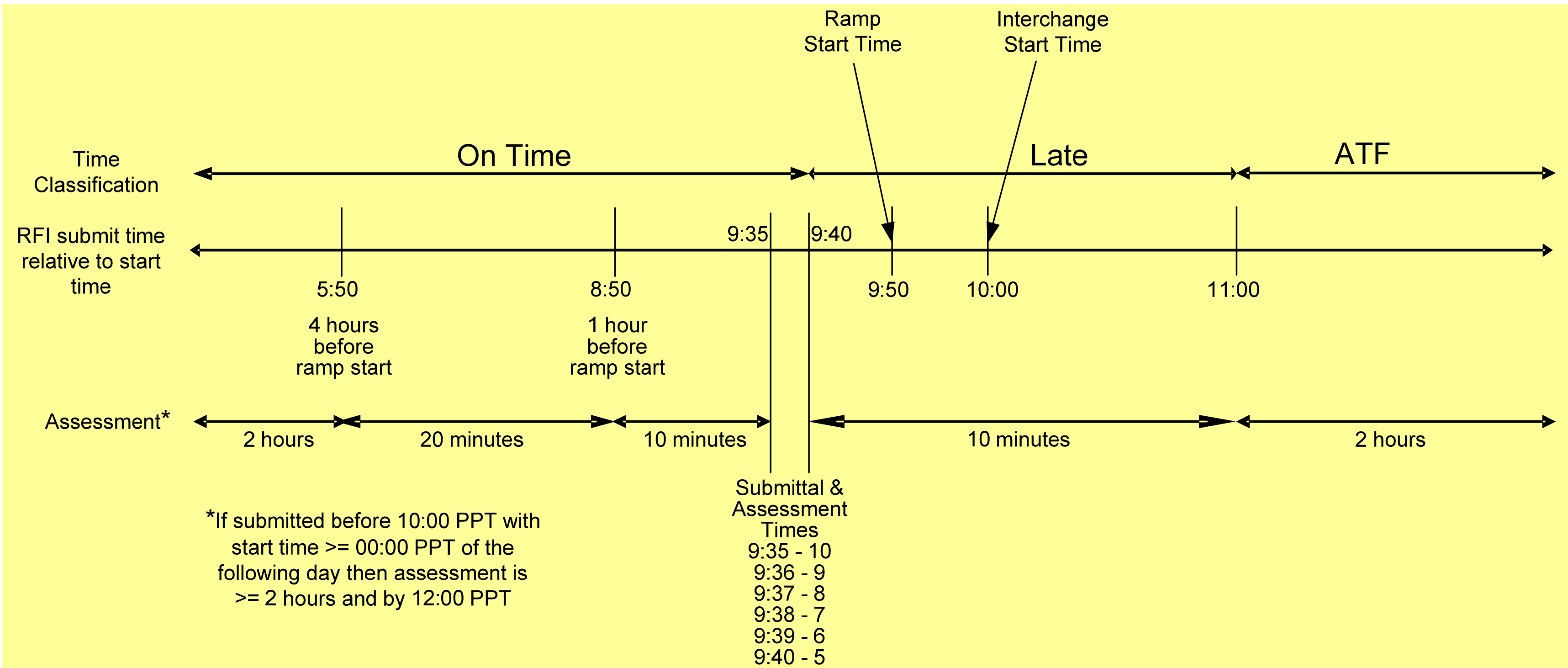


Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange (RFI)[12] is Submitted	**~~IA~~ Assigned Time Classification**	**~~IA~~Sink BA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**~~IA~~Sink BA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
10 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 6 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
12 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 7 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 8 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 9 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1hour and < 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	< 20 minutes from Arranged interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time	≤ 1minute from RFI submission	By 12:00 PPT of day the Arranged Interchange was received by the IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[12] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC



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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Implementation of Interchange**

2. **Number:** **INT-009-2**

3. **Purpose:** To ensure that Balancing Authorities implement the Interchange exactly as agreed upon in the Interchange confirmation process and maintain the generation-to-load balance.

4. **Applicability**

   4.1. Balancing Authority.

5. **Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. No more than one hour prior to each operating hour, each Balancing Authority shall ensure that for that operating hour, the composite of its Confirmed Interchange energy profiles (and any associated modifications to Confirmed Interchange), excluding Dynamic Schedules, with each Adjacent Balancing Authority is:

1.1. Agreed to by that Adjacent Balancing Authority,

1.2. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.3. Opposite in sign to that of the Adjacent Balancing Authority.

R2. Each Balancing Authority shall incorporate in the Net Scheduled Interchange term used in the Balancing Authority's control ACE (or alternate control process):

2.1. The composite of its Confirmed Interchange and any associated modifications to Confirmed Interchange, excluding Dynamic Schedules, as confirmed with its Adjacent Balancing Authorities, including an agreed upon ramp profile,

2.2. Plus Interchange from Dynamic Schedules with its Adjacent Balancing Authorities as determined by metering.

C. Measures

M1. TBD

D. Compliance

1. **TBD**

E. Regional Differences

None identified.

Version History

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Implementation of Interchange**

2. **Number:** **INT-009-~~1~~2**

3. **Purpose:** To ensure that ~~the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority such that the~~ Balancing Authorities implement the Interchange exactly as agreed upon in the Interchange confirmation process and maintain the generation-to-load balance.

4. **Applicability**

   4.1. Balancing Authority.

5. **Effective Date:** ~~January 1, 2007~~ First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. ~~The~~No more than one hour prior to each operating hour, each Balancing Authority shall ~~implement~~ensure that for that operating hour, the composite of its Confirmed Interchange ~~as received from the~~ energy profiles (and any associated modifications to Confirmed Interchange), excluding Dynamic Schedules, with each Adjacent Balancing Authority~~.~~ is:

1.1. Agreed to by that Adjacent Balancing Authority,

1.2. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.3. Opposite in sign to that of the Adjacent Balancing Authority.

R2. [IC1]Each Balancing Authority shall incorporate in the Net Scheduled Interchange term used in the Balancing Authority's control ACE (or alternate control process):

2.1. ~~t~~The composite of its Confirmed Interchange and any associated modifications to Confirmed Interchange, excluding Dynamic Schedules, as confirmed with its Adjacent Balancing Authorities, including an agreed upon ramp profile,

2.2. ~~p~~Plus Interchange from Dynamic Schedules with its Adjacent Balancing Authorities as determined by metering.

C. Measures

M1. TBD

D. Compliance

1. **TBD**

E. Regional Differences

None identified.

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Interchange Initiation and Modification for Reliability**
2. **Number:** **INT-010-2**
3. **Purpose:** Under abnormal operating conditions, allow certain types of Interchange Schedules to be initiated or modified by reliability entities, and to be exempt from compliance with other Interchange Standards.
4. **Applicability**
   - **4.1.** Balancing Authority.
   - **4.2.** Transmission Service Provider.
5. **Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. If as part of a reserve sharing agreement, a Balancing Authority schedules Interchange in duration of more than 60 minutes to replace one or more resources that are no longer available to serve Load, the Sink Balancing Authority shall[1] ensure that a Request for Interchange is created within 60 minutes of the start of the scheduled Interchange, and with a start time no more than 60 minutes beyond the resource loss.

R2. If a Reliability Coordinator directs modification to a Confirmed Interchange schedule for current or imminent reliability-related reasons, the Sink Balancing Authority shall[2] ensure that a request to modify an Arranged Interchange reflecting that modification is created within 60 minutes of the start of the modification.

R3. If a Reliability Coordinator directs the scheduling of Interchange for current or imminent reliability-related reasons, the Sink Balancing Authority shall[3] ensure that a Request for Interchange is created reflecting that Interchange schedule within 60 minutes of the start of the scheduled Interchange.

R4. Balancing Authorities and Transmission Service Providers shall only use a Reliability Adjustment RFI in response to one or more of the following:

- **4.1.** Loss or non-performance of Generation supplying the Interchange
- **4.2.** Loss of Load being served by the Interchange

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[1] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[2] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[3] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

4.3. Loss of one or more Transmission Facilities

4.4. An actual or potential SOL or IROL exceedance

4.5. Any real-time reliability concern related to a specific Confirmed Interchange, provided that concern is supported by evidence.

C. Measures

M1. TBD

D. Compliance

1. TBD

E. Regional Differences

None identified.

Version History

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A. Introduction

1. **Title:** **Interchange ~~Coordination Exemptions~~Initiation and Modification for Reliability**

2. **Number:** **INT-010-~~1~~2**

3. **Purpose:** ~~Allow~~Under abnormal operating conditions, allow certain types of Interchange ~~schedules~~Schedules to be initiated or modified by reliability entities, and to be exempt from compliance with other Interchange Standards ~~under abnormal operating conditions~~.

4. **Applicability**

   4.1. Balancing Authority.

   ~~**4.2.** Reliability Coordinator.~~

   4.2. Transmission Service Provider.

5. **Effective Date:** ~~January 1, 2007~~ First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

~~**R1.** The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required.~~

~~**R2.** For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event.~~

R1. ~~For a new Interchange schedule that is directed by~~If as part of a reserve sharing agreement, a Balancing Authority schedules Interchange in duration of more than 60 minutes to replace one or more resources that are no longer available to serve Load, the Sink Balancing Authority shall[1] ensure that a Request for Interchange is created within 60 minutes of the start of the scheduled Interchange, and with a start time no more than 60 minutes beyond the resource loss.

R2. If a Reliability Coordinator directs modification to a Confirmed Interchange schedule for current or imminent reliability-related reasons, the Sink Balancing Authority shall[2] ensure that a request to modify an Arranged Interchange reflecting that modification is created within 60 minutes of the start of the modification.

[1] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[2] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

R3. If a Reliability Coordinator directs the scheduling of Interchange for current or imminent reliability-related reasons, the ~~Reliability Coordinator~~Sink Balancing Authority shall ~~direct~~ [3] ensure that a ~~Balancing Authority to submit an Arranged Interchange~~ Request for Interchange is created reflecting that Interchange schedule within 60 minutes of the ~~initiation of the event~~start of the scheduled Interchange.

R4. Balancing Authorities and Transmission Service Providers shall only use a Reliability Adjustment RFI in response to one or more of the following:

4.1. Loss or non-performance of Generation supplying the Interchange

4.2. Loss of Load being served by the Interchange

4.3. Loss of one or more Transmission Facilities

4.4. An actual or potential SOL or IROL exceedance

4.5. Any real-time reliability concern related to a specific Confirmed Interchange, provided that concern is supported by evidence.

C. Measures

M1. TBD

D. Compliance

1. TBD

E. Regional Differences

None identified.

Version History

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[3] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

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Interchange Coordination – The act of using commonly available tools to ensure that the transfer of energy from one Balancing Authority to another is undertaken with full disclosure to all the parties involved

A. Introduction

1. **Title:** **Interchange Coordination Support**

2. **Number:** **INT-011-1**

3. **Purpose:** To describe capabilities that registered entities must provide to support Interchange Coordination.

4. **Applicability**

   4.1. Purchasing Selling Entity.

   4.2. Balancing Authority.

   4.3. Transmission Service Provider.

   4.4. Reliability Coordinator.

5. **Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Purchasing Selling Entity and Balancing Authority that desires to submit Requests for Interchange shall[1] have the capability to electronically:

1.1. Submit a Request for Interchange to a Load Balancing Authority.

1.2. Submit a request to modify Interchange

1.3. Receive distributions of Confirmed Interchange

1.4. Receive distributions of modifications to Interchange

R2. Each Sink Balancing Authority shall[2] have the capability to electronically:

2.1. Receive a Request for Interchange

2.2. Receive a request to modify Interchange

2.3. Validate Requests for Interchange as follows:

2.3.1. Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).

2.3.2. All reliability entities involved in the Arranged Interchange are currently in the entity registry.

2.3.3. Generation source and load sink are defined.

2.3.4. Megawatt profile is defined.

---

[1] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

[2] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

2.3.5. Interchange duration is defined.

2.4. Validate request to modify Interchange as follows:

2.4.1. Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).

2.4.2. Megawatt profile is defined.

2.4.3. Interchange duration is defined.

2.5. Distribute the validated Request for Interchange as Arranged Interchange

2.6. Distribute the validated requested modifications as an Arranged Interchange

2.7. Receive communication of approval or denial of Arranged Interchange

2.8. Distribute notification as each entity approves or denies an Arranged Interchange.

2.9. Transition Arranged Interchange to Confirmed Interchange if all approvals are received.

2.10. Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

2.11. Submit a request to modify Interchange

R3. Each Balancing Authority and Transmission Service Provider, and any Purchasing Selling Entity that desires or is required to approve or deny Arranged Interchange, shall[3] have the capability to electronically:

3.1. Receive distribution of Arranged Interchange

3.2. Communicate approval or denial of the Arranged Interchange to the Load Balancing Authority

3.3. Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.

3.4. Submit a request to modify Interchange

C. Measures

M1. TBD

D. Compliance

1. TBD

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

[3] In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred.

> The CI SDT recommends retiring this standard:
>
> The CI SDT recommends revising R1 and R1.1 and moving them into INT-004-3.
>
> The CI SDT recommends retiring R2, R2.1 and R2.2.

A. Introduction

1. **Title: Interchange Information**
2. **Number:** INT-001-3
3. **Purpose:**
   To ensure that Interchange information is submitted to the NERC-identified reliability analysis service.
4. **Applicability:**
   4.1. Purchase-Selling Entities.
   4.2. Balancing Authorities.
5. **Effective Date:** August 27, 2008 (U.**S.)**
   NERC Board Approval: October 9, 2007

B. Requirements

R1. The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:

R1.1. All Dynamic Schedules at the expected average MW profile for each hour.

R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:

R2.1. If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.

R2.2. For each bilateral Inadvertent Interchange payback.

C. Measures

M1. The Purchasing-Selling Entity that serves the load shall have and provide upon request evidence that could include but is not limited to, its 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 Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour as specified in Requirement 1.

M2. Each Sink 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 Arranged Interchange was submitted to the Interchange Authority as specified in Requirements 2.1 and 2.2.

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

The Purchasing-Selling Entity that serves load and Sink Balancing Authority shall each 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. Levels of Non-Compliance for Sink Balancing Authorities:

2.1. Level 1: One instance of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and R2.2.

2.2. Level 2: Two instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

2.3. Level 3: Three instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

2.4. Level 4: Four or more instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

3. Levels of Non-Compliance for Purchasing-Selling Entities that Serve Load:

3.1. Level 1: One instance of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.2. Level 2: Two instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.3. Level 3: Three instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.4. Level 4: Four or more instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

E. Regional Differences

1. MISO Energy Flow Information Waiver effective on 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	October 9, 2008	Adopted by Board of Trustees (Remove WECC Waiver)	Revised
3	July 21, 2008	Regulatory Approval	Revised

The CI SDT recommends retiring this standard:

The CI SDT recommends revising R1, R1.1, R1.1.1, R1.1.2, and R1.2 and moving them into INT-009-2

A. Introduction

1. **Title: Interchange Transaction Implementation**
2. **Number:** INT-003-2
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

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.

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including:

R1.1.1. Interchange Schedule start and end time.

R1.1.2. Energy profile.

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.

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. Levels of Non-Compliance for Balancing Authorities:

2.1. Level 1: There shall be a separate Level 1 non-compliance, if either of the following conditions exists:

2.1.1 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.

2.1.2 One instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

2.2. **Level 2:** There shall be a separate Level 2 non-compliance, if either of the following conditions exists:

2.2.1 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.

2.2.2 Two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

2.3. **Level 3:** There shall be a separate Level 3 non-compliance, if either of the following conditions exists:

2.3.1 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.

2.3.2 Three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

2.4. **Level 4:** There shall be a separate Level 4 non-compliance, if either of the following conditions exists:

2.4.1 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.

2.4.2 Four or more 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

The CI SDT recommends retiring this standard:

The CI SDT recommends revising R1 and R1.1 and moving them into INT-006-3.

A. Introduction

1. **Title:** **Interchange Authority Distributes Arranged Interchange**

2. **Number:** INT-005-3

3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is distributed by an Interchange Authority such that Interchange information is available for reliability assessments.

4. **Applicability:**

   4.1. Interchange Authority.

5. **Effective Date:** The standard shall become effective on the first day of the first calendar quarter, three months after all regulatory approvals.

B. Requirements

R1. Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange.

R1.1. When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall be able to provide evidence that it has distributed the Arranged Interchange information to all reliability entities involved in the Interchange within the applicable time frame.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

1.3. Data Retention

The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a specific complaint of failure to perform R1. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate the Interchange Authority's distribution of all Arranged Interchange information to all reliability entities involved in an Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Interchange Authority.

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate that the Interchange Authority distributed the Arranged Interchange information to all reliability entities involved in that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not distributing information to all involved reliability entities as described in R1.

2.2. Level 2: Two occurrences[1] of not distributing information to all involved reliability entities as described in R1.

2.3. Level 3: Three occurrences[1] of not distributing information to all involved reliability entities as described in R1.

2.4. Level 4: Four or more occurrences[1] of not distributing information to all involved reliability entities as described in R1 or no evidence provided.

E. Regional Differences

None

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised

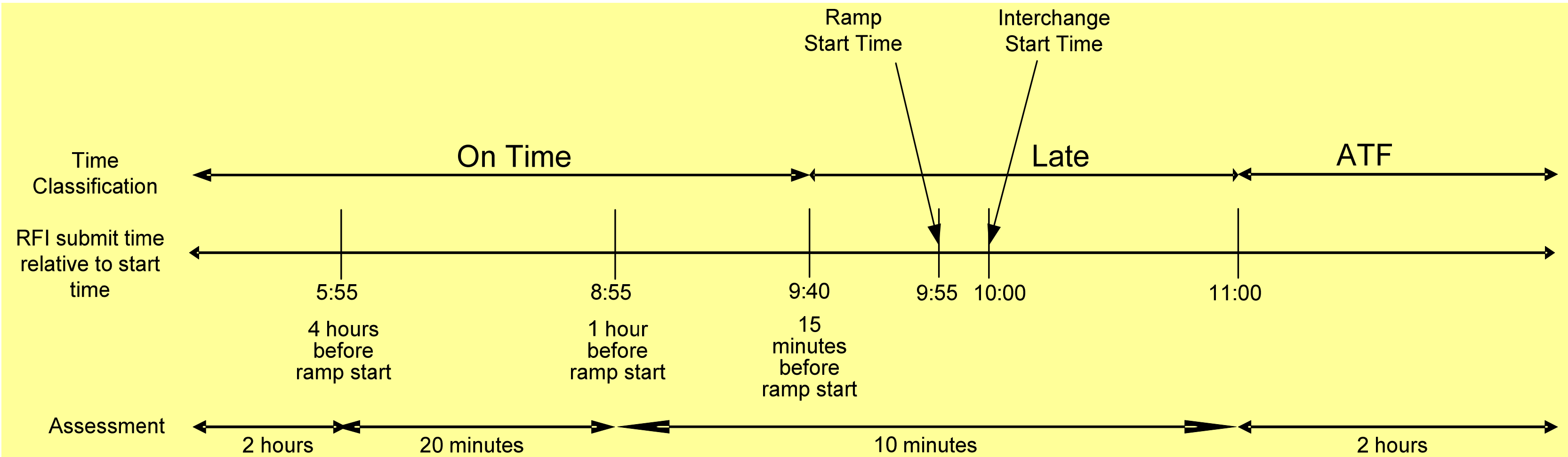
[1] This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange (RFI)[2] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the RFI start time	ATF	≤ 1 minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
<15 minutes prior to ramp start and ≤1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[2] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC

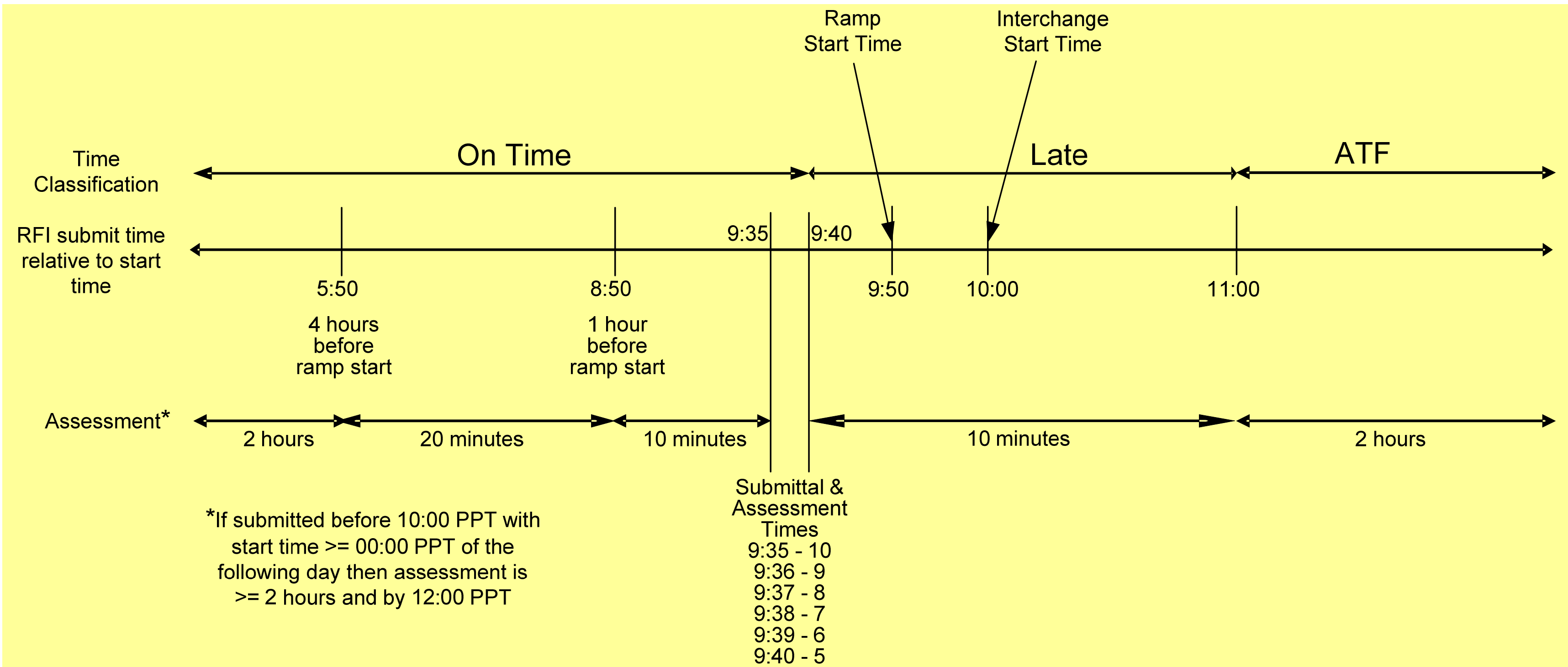


Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange (RFI)[3] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
10 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 6 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
12 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 7 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 8 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 9 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1hour and < 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	< 20 minutes from Arranged interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time	≤ 1minute from RFI submission	By 12:00 PPT of day the Arranged Interchange was received by the IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC



The CI SDT recommends retiring this standard:

The CI SDT recommends revising R1, R1.1, R1.2, R1.3, R1.3.1, R1.3.2, R1.3.3, R1.3.4, and R1.4 and moving them into INT-006-3

A. Introduction

1. **Title:** **Interchange Confirmation**
2. **Number:** **INT-007-1**
3. **Purpose:** To ensure that each Arranged Interchange is checked for reliability before it is implemented.
4. **Applicability**

   4.1. Interchange Authority.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following:

R1.1. Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).

R1.2. All reliability entities involved in the Arranged Interchange are currently in the NERC registry.

R1.3. The following are defined:

R1.3.1. Generation source and load sink.

R1.3.2. Megawatt profile.

R1.3.3. Ramp start and stop times.

R1.3.4. Interchange duration.

R1.4. Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall show evidence that it has verified the Arranged Interchange information prior to the dissemination of the Confirmed Interchange.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.

1.3. Data Retention

The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate an Interchange Authority's verification that all Arranged Interchange was balanced and valid as defined in R1. The Compliance Monitor may request up to a three-month period of historical data ending with the date the request is received by the Interchange Authority.

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate an Interchange Authority's verification that an Arranged Interchange was balanced and valid as defined in R1 for that specific Interchange

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] where Interchange-related data was not verified as defined in R1.

2.2. Level 2: Two occurrences where Interchange-related data was not verified as defined in R1.

2.3. Level 3: Three occurrences where Interchange-related data was not verified as defined in R1.

2.4. Level 4: Four or more occurrences where Interchange-related data was not verified as defined in R1.

E. Regional Differences

None

[1] This does not include instances of not verifying due to extenuating circumstances approved by the Compliance Monitor.

Version History

Version	Date	Action	Change Tracking

The CI SDT recommends retiring this standard:

The CI SDT recommends revising R1, R1.1, R1.1.1, and R1.1.2 and moving them into INT-006-3

A. Introduction

1. **Title:** **Interchange Authority Distributes Status**
2. **Number:** INT-008-3
3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority.
4. **Applicability:**
   4.1. Interchange Authority.
5. **Effective Date:** The standard shall become effective on the first day of the first calendar quarter, three months after all regulatory approvals.

B. Requirements

R1. Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange.

R1.1. For Confirmed Interchange, the Interchange Authority shall also communicate:

R1.1.1. Start and stop times, ramps, and megawatt profile to Balancing Authorities.

R1.1.2. Necessary Interchange information to NERC-identified reliability analysis services.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall provide evidence that it has distributed the final status and Confirmed Interchange information specified in Requirement 1 to all Balancing Authorities, Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange within the time period defined in the Timing Table, Column C. If denied, the Interchange Authority shall tell all involved parties that approval has been denied.

M1.1 For each Arranged Interchange that includes a direct current tie, the Interchange Authority shall provide evidence that it has communicated the final status to the Balancing Authorities on both sides of the direct current tie, even if the Balancing Authorities are neither the Source nor Sink for the Interchange.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last non-compliance to R1.

1.3. Data Retention

The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance will be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate the Interchange Authority's distribution of all Arranged Interchange final status and Confirmed Interchange information to all entities involved in an Interchange per R1. The Compliance Monitor may request up to a three-month period of historical data ending with the date the request is received by the Interchange Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate that the Interchange Authority distributed the Arranged Interchange final status and Confirmed Interchange information to all entities involved in that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not distributing final status and information as described in R1.

[1] This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.

2.2. Level 2: Two occurrences[1] of not distributing final status and information as described in R1.

2.3. Level 3: Three occurrences[1] of not distributing final status and information as described in R1.

2.4. Level 4: Four or more occurrences[1] of not distributing final status and information as described in R1 or no evidence provided.

E. Regional Differences

None.

Version History

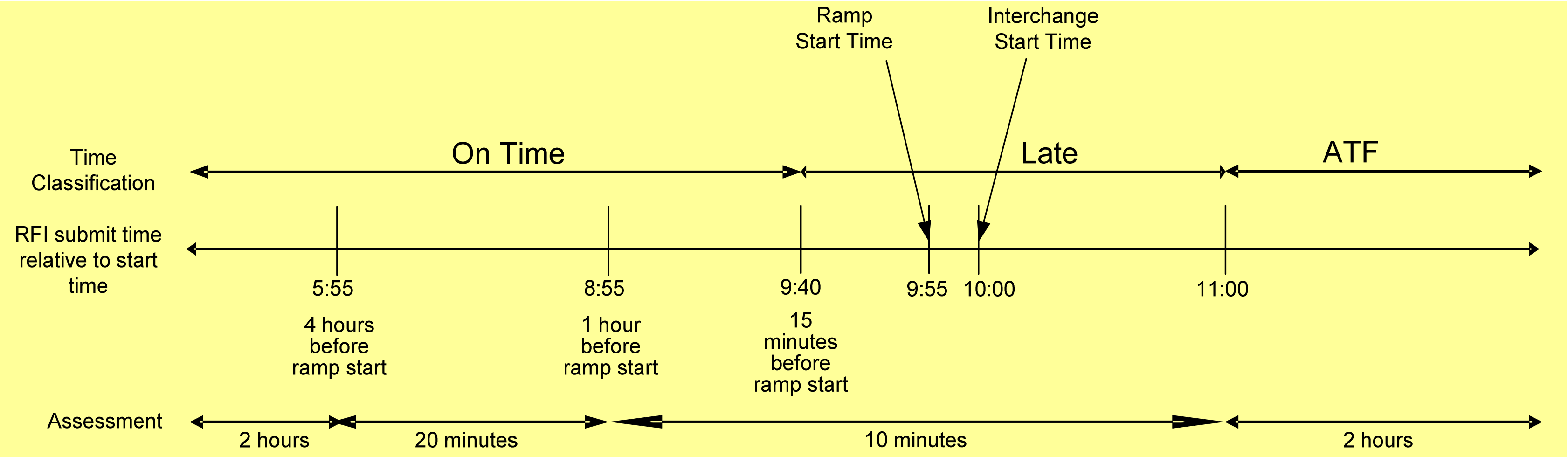
Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange (RFI)[2] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the RFI start time	ATF	≤ 1 minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
<15 minutes prior to ramp start and ≤1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[2] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC

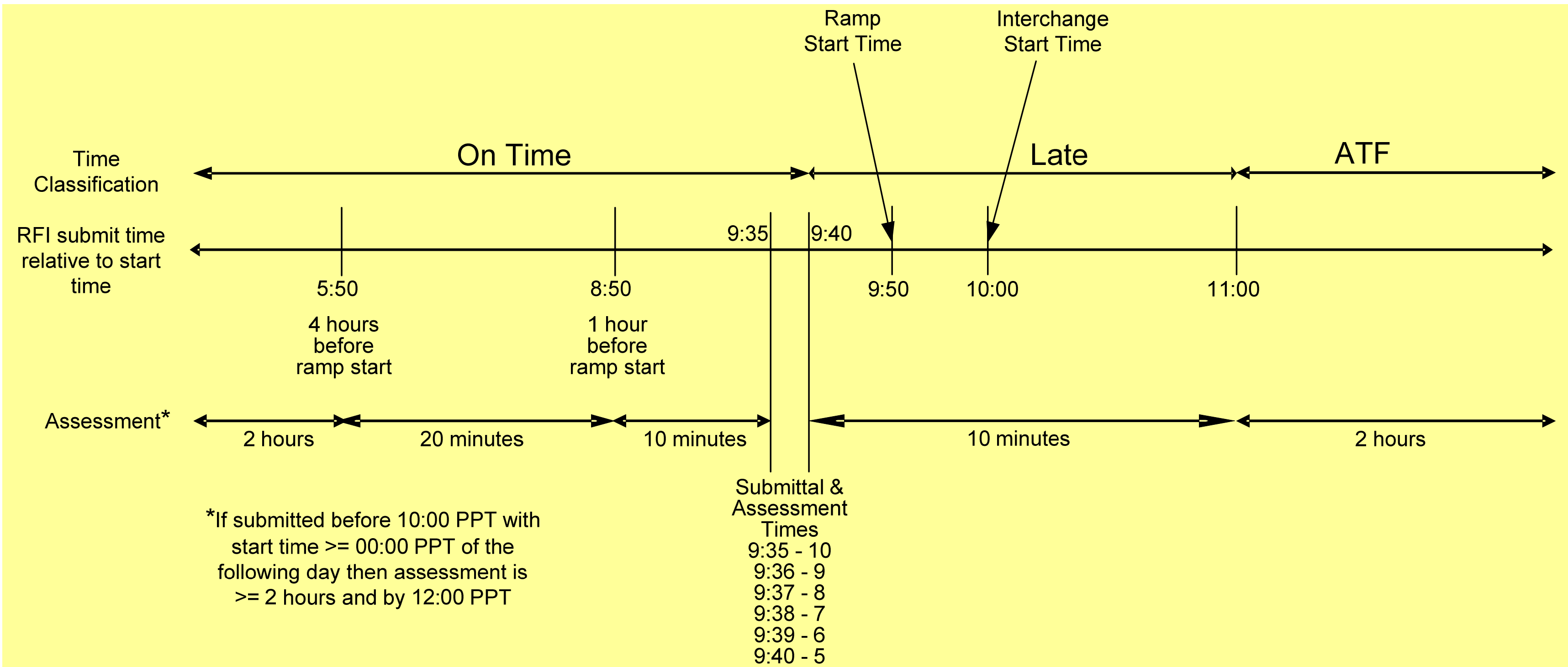


Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange (RFI)[3] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
10 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 6 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
12 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 7 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 8 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 9 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1hour and < 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	< 20 minutes from Arranged interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time	≤ 1minute from RFI submission	By 12:00 PPT of day the Arranged Interchange was received by the IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC



NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form for Project 2008-12 — Coordinate Interchange

Please **DO NOT** use this form. Please use the electronic comment form at the link below to submit comments on the current drafts of INT-004-3, INT-006-4, INT-009-2, INT-010-2, and INT-011-1. Comments must be submitted by **December 11, 2009.** If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-452-8060.

http://www.nerc.com/filez/standards/Project2008-12_Coordinate_Interchange_Stds_Modifications.html

Background Information

The Coordinate Interchange Standards Drafting Team has been charged with reviewing and modifying the INT family of standards. At this time, the CI SDT believes that the best strategy for addressing these standards is one based on two phases. The first phase will address issues related to the Interchange Authority function and the relationship with Electronic Tagging (E-Tag), as well as FERC's directives from Order 693. The second phase will address issues related to dynamic transfers in detail, as well as backup plans. The documents posted with this comment form are the first draft of the phase one standards.

This approach differs from that originally described in the SAR. The language on the SAR states:

> "The first phase is needed as soon as possible and should focus on the revisions needed to ensure that each requirement is assigned to a user, owner or operator of the bulk power system. All other proposed revisions should be addressed in the second or subsequent phase(s) of the project."

As the CI SDT began to work to develop the Phase I changes, the team quickly found that simply identifying clearly the entity to which a particular requirement applied would be insufficient to address the underlying concerns regarding the assignment of responsibilities. The debate regarding whether or not the Interchange Authority was a registered entity or a software tool (which the CI SDT believes was the primary driver for the proposal for Phase I) could not be resolved without reconsidering the details of the requirements. Instead, the CI SDT felt is was necessary to more clearly identify not only the correct entities, but the associated responsibilities of those entities. Accordingly, the CI SDT developed this more comprehensive proposal.

The CI SDT recognizes that these standards are in many cases a significant departure from the current set of standards. Accordingly, the following overview is intended to describe the standards and how they have been changed:

- **INT-001-3 — Interchange Information** — To be retired. R1 and R1.1 were moved to INT-004-3, where they were further modified. R2, R2.1, and R2.2 were moved to INT-009-2, where they were subsequently removed as unnecessary.
- **INT-003-2 — Interchange Transaction Implementation** — To be retired. R1, R1.1, R1.1.1, R1.1.2, and R1.2 were moved to INT-009-2, where they were further modified.
- **INT-004-3 — Dynamic Schedules** — This standard was clarified, but largely retained from INT-004-2. The requirement to tag Dynamic Schedules

(R1 and R1.1) from INT-001-3 was moved to this standard and replaces the requirement related to transaction reloading that was erroneously included in INT-004-2.

- **INT-005-3 — Interchange Authority Distributes Arranged Interchange** — To be retired. R1 and R1.1 were moved to INT-006-3, where they further modified.
- **INT-006-4 — Evaluation of Interchange Transactions** — This standard incorporates and expands upon the requirements specified in INT-005-3 (R1 and R1.1), INT-006-2, INT-007-1 (R1, R1.1, R1.2, R1.3, R1.3.1, R1.3.2, R1.3.3, R1.3.4, and R1.4), and INT-008-2 (R1, R1.1, R1.1.1, and R1.1.2). Requirements R8 and R9 regarding the role of the Transmission Operator and the Reliability Coordinator were added to address directives in FERC Order 693.
- **INT-007-1 — Interchange Confirmation** — To be retired. R1, R1.1, R1.2, R1.3, R1.3.1, R1.3.2, R1.3.3, R1.3.4, and R1.4 were moved to INT-006-3, where they were further modified.
- **INT-008-3 — Interchange Authority Distributes Status** — To be retired. R1, R1.1, R1.1.1, and R1.1.2 were moved to INT-006-3, where they were further modified.
- **INT-009-2 — Implementation of Interchange** — This standard was clarified and expanded, but largely retained from INT-009-1 and INT-003-2 (R1, R1.1, R1.1.1, R1.1.2, and R1.2).
- **INT-010-2 — Interchange Initiation and Modification for Reliability** — This standard was clarified and expanded, but largely retained from INT-010-1. A new requirement R4 was added to limit when entities may use Reliability Adjustment Requests for Interchange.
- **INT-011-1 — Interchange Coordination Support** — This is a new standard that attempts to address the relationship between the INT standards and E-Tag. It specifies, at a high level, that during normal operations, entities must have systems capable of meeting basic tagging requirements.

With specific regard to the Interchange Authority (IA), the CI SDT believes that the IA is not an actual entity, but a function that is performed by the Sink Balancing Authority. This approach has been reviewed with the leadership of the Functional Model Working Group, which has agreed that the INT standards assigning those functions to the Sink Balancing Authority directly would not conflict with the functional model. Accordingly, the team is proposing to remove the IA from these standards. Since the current INT standards are the only ones that specify the role of the IA, the team believes that if the IA is removed from the INT standards, there will no longer be a need for entities to register as an IA. Although other standards (such as CIP-001 through -009) refer to the IA, they do so by including the IA in a class of entities that are subject to a requirement based on that class; they do not mandate any IA-specific tasks in those requirements. As such, the team proposes to remove the IA as a functional entity from CIP-001 through -009, as well as from any other standards that refer to the IA in a generic way (i.e., not specifying Interchange tasks to be performed by an Interchange Authority), and to modify any standards or definitions that refer to the IA more specifically.

The Coordinate Interchange Standards Drafting Team is seeking comments on these draft standards.

1. **Do you agree that the “two phase” approach (in which the IA issues, 693 directives, and E-Tag relationship are addressed in a first phase, followed by a second phase to address dynamic transfers and backup plans) is appropriate?**

   ☐ Yes
   ☐ No

   If no, what do you believe the correct approach should be?
   Comments:

2. **As discussed above, the CI SDT believes that the IA is not an actual entity, but a function that is performed by the Sink Balancing Authority. This approach has been reviewed with the leadership of the Functional Model Working Group, which has agreed that the INT standards assigning those functions to the Sink Balancing Authority directly would not conflict with the functional model. Accordingly, the team is proposing to remove the IA from these standards.**

   Do you agree with the IA being removed from these standards?

   ☐ Yes
   ☐ No

   If no, please explain why you believe the IA should be retained.
   Comments:

3. **As a part of removing the IA from these standards, the CI SDT defined a new term that is used in the purpose statement of INT-011-1:**

   > **Interchange Coordination** – The act of using commonly available tools to ensure that the transfer of energy from one Balancing Authority to another is undertaken with full disclosure to all the parties involved

   Given the term’s use in the INT-011-1 purpose, do you agree with this definition?

   ☐ Yes
   ☐ No

   If no, please explain your answer.
   Comments:

4. **As a part of removing the IA from these standards, the CI SDT identified several key tasks that Balancing Authorities, Purchasing Selling Entities, and Transmission Service Providers must be able to accomplish as part of Interchange Coordination. These tasks have been specified in INT-011-1 (due to its length, the list of tasks is not reproduced here).**

   Do you agree that these tasks must be specified in a standard as requirements?

   ☐ Yes

☐ No

If no, please explain you answer.
Comments:

5. **In the past, the industry has expressed concerns regarding how to manage Interchange transactions in the event of cyber attack or other incident. In response, the CI SDT has proposed that several requirements in INT-004-3, INT-006-3 and INT-011-1 be footnoted with the following "In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred."**

   In other cases, such as INT-009-2, this language was not included, indicating that at all times, regardless of tool availability, entities are expected to ensure that Interchange is coordinated, agreed to, and implemented as agreed.

   Do you agree that this phrase and its selective use appropriately addresses concerns with managing Interchange transactions in the event of cyber attack or other incident?

   ☐ Yes
   ☐ No

   If no, please propose alternate language or a different approach.
   Comments:

6. **INT-001-2 R2 requires:**

   > **R2.** The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:
   >
   > > **R2.1.** If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.
   > >
   > > **R2.2.** For each bilateral Inadvertent Interchange payback.

   The CI SDT believes that this is no longer required. Since the proposed INT-009-2 R2 makes is clear that the Net Scheduled Interchange term in the control equation can only include Confirmed Interchange as agreed to between Balancing Authorities and metered values for Dynamic Schedules, this by definition requires that an Arranged Interchange be created in order to implement the schedules listed in R2.1 and R2.2. From a reliability perspective, it is unimportant who creates these Arranged interchanges – only that they be created and confirmed prior to being entered into the control equation.

   Do you agree that INT-001-2 R2 is no longer required, and does not need to be retained?

   ☐ Yes
   ☐ No

If no, please explain why you believe the requirement is still needed.
Comments:

7. **INT—004-2 R1 requires:**

   R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.

   The CI SDT believes that at a minimum, this requirement does not belong in the "Dynamic Schedules" standard. However, for several reasons, the CI SDT further believes that this specific requirement is no longer required:

   - It mandates a practice (releasing of E-Tag limits) that is more process related
   - The practice is already addressed in related NAESB standards (WEQ-004 Appendix B - E-Tag Actions[1])
   - Use of a limit (and the associated release of that limit) is only one particular way to address curtailments. Other ways exist that could be used in lieu of this approach. The reliability standard should not mandate a single approach when others may suffice.

   Do you agree INT-004-2 R1 can be eliminated?

   ☐ Yes
   ☐ No

   If no, please explain why the requirement is still needed.
   Comments:

8. **Requirements R1 and R7 in INT-006-4 have been created to address earlier requirements related to the distribution of Interchange information within one minute of a specific action. This one minute limit seemed in most cases to have little or no impact on reliability. The CI SDT discussed this issue at length, and attempted to determine a way in which the one minute requirement only would apply only if its exceedence resulted in a case where the ability to schedule the transaction reliably could have been hindered by the delay. To do this, the CI SDT created several criteria which must be met to constitute a violation:**

   R1. Each Sink Balancing Authority shall distribute all Arranged Interchange to the Source Balancing Authority, each Intermediate Balancing Authority, each Reliability Coordinator, and each Transmission Service Provider included in the Arranged Interchange less than one minute after receipt of any associated Request for Interchange or requested modifications to Confirmed or Implemented Interchange that meets all of the following criteria:

   1.1. The Request for Interchange or requested modification to Confirmed or Implemented Interchange was received by the Sink Balancing Authority on-time, and

[1] Commenters that wish to gain access to review NAESB WEQ-004 should contact NAESB at www.naesb.org and request information regarding the options available for acquiring access to NAESB standards.

1.2. The Arranged Interchange was not transitioned to Confirmed Interchange, and

1.3. Notification of the Arranged Interchange being transitioned to Confirmed Interchange was distributed less than three minutes prior to the requested ramp start, and

1.4. The Arranged Interchange was not denied by any approval entity.

R7. Each Sink Balancing Authority shall distribute all notifications of whether or not Arranged Interchange was transitioned to Confirmed Interchange to the Source Balancing Authority, each Intermediate Balancing Authority, each Reliability Coordinator, and each Transmission Service Provider included in the Arranged Interchange less than one minute after making the decision to transition or not for any Arranged Interchange that meets all of the following criteria:

7.1. The Request for Interchange or requested modification to Confirmed or Implemented Interchange was received by the Sink Balancing Authority on-time, and

7.2. Notification of whether or not the Arranged Interchange was transitioned to Confirmed Interchange was not distributed three or more minutes prior to the requested ramp start, and

7.3. Not all entities actively responded during the reliability assessment period defined in the timing requirements in Attachment 1, column B, and

7.4. The Arranged Interchange was not denied by any approval entity.

Do you agree with this approach?

☐ Yes
☐ No

If no, what do you believe the correct approach should be?
Comments:

9. **Requirements R2.1 and R3.1 in INT-006-4 now list specific reasons for which a Balancing Authority or Transmission Provider, respectively, must deny an arranged Interchange:**

2.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange if 1.) it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange, and/or 2.) the scheduling path (proper connectivity of Adjacent Balancing Authorities) is invalid.

3.1. Transmission Service Providers shall deny the Arranged Interchange if 1.) the unscheduled capacity remaining for the Transmission Service Request (or other contractual/tariff arrangement) on the Transmission Providers system will not accommodate the Arranged Interchange, 2.) the Transmission system does not have the capability to accommodate the Arranged Interchange based on projected system conditions, or 3.) the transmission path (proper connectivity of adjacent Transmission Service Providers) is invalid.

Do you agree that these reasons should be specified and that the reasons listed are appropriate?

☐ Yes
☐ No

If no, please explain your answer.
Comments:

10. **Requirement R4 in INT-006-4 now requires that Reliability Adjustment Requests for Interchange (i.e., curtailments) must be approved by each of the appropriate Balancing Authorities "if (the BA) can support the magnitude of the Interchange, including ramping, throughout the duration of the Reliability Adjustment Request for Interchange."**

    Do you agree that in the case of curtailment, a Balancing Authority must approve the curtailment unless the magnitude of Interchange, including ramping, cannot be supported?

    ☐ Yes
    ☐ No

    If no, what do you believe are valid reasons for denying a curtailment?
    Comments:

11. **Requirements R5 and R6 of INT-006-4 list the criteria which a Sink Balancing Authority must use to determine whether an Arranged Interchange should be transitioned to a Confirmed Interchange or not:**

> **R5.** Each Sink Balancing Authority shall transition Arranged Interchange to Confirmed Interchange if any of the following conditions are met:
>
> **5.1** All entities associated with the Arranged Interchange have communicated their approval of the transition
>
> **5.2** The Arranged Interchange represents a Reliability Adjustment and the Source Balancing Authority, direct-current tie Operating Balancing Authority, and the Sink Balancing Authority associated with the Arranged Interchange have communicated their approval of the transition
>
> **5.3** The time period specified in Attachment 1, column B, has elapsed, all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transitions, and no other entities associated with the Arranged Interchange have communicated their denial of the transition.
>
> **R6.** Each Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange if any of the following conditions are met:
>
> **6.1** The Arranged Interchange represents a Reliability Adjustment; the time period specified in Attachment 1, column B, has elapsed; and one or more of the following entities associated with the Arranged Interchange have not communicated their approval of the transition: the Source Balancing

Authority, the direct-current tie Operating Balancing Authority, or the Sink Balancing Authority.

6.2 The Arranged Interchange does not represent a Reliability Adjustment; the time period specified in Attachment 1, column B, has elapsed; and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition

6.3 The Arranged Interchange does not represent a Reliability Adjustment, the time period specified in Attachment 1, column B, has elapsed, and any entity associated with the Arranged Interchange has communicated their denial of the transition

Do you agree that these criteria are correct?

☐ Yes
☐ No

If no, what do you believe the correct criteria should be?
Comments:

12. **In Order 693, FERC issued directives that with regard to the INT standards, NERC include Reliability Coordinators and Transmission Operators as applicable entities, as well as require Reliability Coordinators and Transmission Operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the Sink Balancing Authorities' necessary transaction modifications before implementation. In response, the CI SDT proposes to add Requirements R8 and R9 of INT-006-3:**

    R8. On a day-ahead basis, each Transmission Operator shall notify the associated Sink Balancing Authority(ies) of any Interchange modifications potentially required to mitigate any previously identified expected SOL or IROL exceedances.

    R9. On a day-ahead basis, each Reliability Coordinator shall notify the associated Sink Balancing Authority(ies) of any Interchange modifications potentially required to mitigate any previously identified expected IROL exceedances.

    Do you believe that these new requirements will adequately address the FERC directive?

    ☐ Yes
    ☐ No

    If no, how do you think the directive should be addressed?
    Comments:

13. **In INT-010-2, the CI SDT has added Requirement R4 to specify when it is appropriate to use Reliability Adjustment Requests for Interchange (i.e., curtailment):**

R4. Balancing Authorities, Transmission Service Providers, and Reliability Coordinators shall only utilize a Reliability Adjustment Request for Interchange in response to the following

4.1 Loss or non-performance of Generation supplying the Interchange

4.2 Loss of Load being served by the Interchange

4.3 Loss of one or more Transmission Facilities

4.4 An actual or potential SOL or IROL exceedance

4.5 Any real-time reliability concern related to a specific Confirmed Interchange, provided that concern is supported by evidence.

Do you believe these limitations are appropriate?

☐ Yes
☐ No

If not, what other reasons should be included?
Comments:

14. In INT-009-2 R1, the CI SDT has proposed that:

No more than one hour prior to each operating hour, each Balancing Authority shall ensure that for that operating hour, the composite of its Confirmed Interchange energy profiles (and any associated modifications to Confirmed Interchange), excluding Dynamic Schedules, with each Adjacent Balancing Authority is:

- Agreed to by that Adjacent Balancing Authority,
- Identical in magnitude to that of the Adjacent Balancing Authority, and
- Opposite in sign to that of the Adjacent Balancing Authority.

The CI SDT chose not to specify a method to reach agreement when conflicts arise, instead assuming that entities will develop their own procedures to resolve conflicts. Should this requirement be modified to include a default procedure that must be used if one does not already exist?

☐ Yes
☐ No

If yes, please offer proposals for such a procedure.
Comments:

15. The CI SDT has made significant attempts to consolidate, clarify, and organize the standards such that they accurately reflect the manner in which the industry currently operates and mandate appropriate levels of performance. Are there any requirements that you think are missing from these standards?

☐ Yes
☐ No

If yes, please elaborate.
Comments:

16. Are you aware of any conflicts between the proposed standards and any regulatory function, rule / order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes
☐ No

If yes, please explain your answer.
Comments:

17. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standards.

Comments:

Source	Standard No.	Project No	Issue	Response
FERC Order 693	INT-001-1	2009-03	Regional Difference to INT-001/4: WECC Tagging Dynamic Schedules and Inadvertent Payback: Submit a filing within 90 days of the Order that provides the needed information or withdraws the regional variance.	Regional differences removed prior to SDT creation.
FERC Order 693	INT-001-2	2009-03	Consider Santa Clara's comments about the applicability of the LSE in the standard as part of the standards development process. "Santa Clara submits that LSEs should be applicable entities under proposed revised INT-001-2 to ensure that they have adequate notice of the requirements of this Reliability Standard. It states that the actions of LSEs are implicated in Requirement R1 of this proposed Reliability Standard."	The SDT has considered these comments. By tightening the language in INT-009 regarding implementation of interchange, the SDT believes that an LSE will have an incentive to provide the information required in the standard, making it effectively a self-policing standard.
FERC Order 693	INT-001-2	2009-03	Include a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.	The SDT believes this is inappropriate, as these transactions are not "INTERCHANGE." The SDT provided this explanation to FERC staff, and FERC staff seemed to understand the issue and was open to alternate proposals. Following discussions with FERC staff, the SDT will investigate creating a modification to the IRO standards that explicitly requires the currently informal practice of RC's requiring the tagging of internal transactions that have a significant reliability impact to congested parts of their systems.
FERC Order 693	INT-004-1	2009-03	Consider adding levels of non-compliance to the standard.	The SDT will add VSLs and VRFs to the standards in a future posting.
FERC Order 693	INT-005-2	2009-03	Consider adding levels of non-compliance to the standard.	The SDT will add VSLs and VRFs to the standards in a future posting.
FERC Order 693	INT-006-1	2009-03	Consider the suggestions made by EEI and TVA and address questions raised by Entergy and Northern Indiana as part of the standard development process. EEI: "EEI states that the "wide-area reliability impact" review envisioned by the Commission, which involves review of the composite energy interchange transactions, probably already takes place under Reliability Standards INT-005 through INT-009 in a cost-effective manner. EEI explains that since most transactions submitted by wholesale markets to the transactions tagging process span multiple hours with varying sizes (in MW), and are often submitted days before transaction start times, the wide-area review consists of ensuring that sufficient generator ramping capability exists, as well as examining	EEI - Wide-area view provisions for the RC and TO have been added, and not allowed to occur more than 48 hours ahead of time. TVA - The team did not use "composite" interchange in its requirement – instead, the team used "aggregated" interchange. Entergy - The changes as written by the team will not require significant tagging rewrites, as no new approval process is being required. Northern Indiana - The team did not require RCs and TOs to validate interchange, but to "review and identify."

Source	Standard No.	Project No	Issue	Response
			for limits on transfer capabilities. This review is generally considered sufficient to the extent that analyses are taking place on the basis of projected system conditions. EEI suggests that the Commission-proposed review and validation of composite energy interchange transactions by reliability coordinators might be more effectively addressed through “near real-time” system review. It explains that, at this time, the broad range of system condition parameters is better known, and the reliability coordinators can make use of the TLR process to maintain system reliability.” TVA: “TVA suggests that the term “composite Tag” should be defined as part of the proposed modifications. CAISO also questions the meaning of “composite Tag” and seeks clarification on that issue. TVA notes that depending on the type of reliability analysis required to validate a “composite Tag,” it may prove impractical to conduct this evaluation for hourly transactions.” Entergy: “Entergy disagrees with the Commission’s proposed modifications. It contends that they will require substantial changes to the tagging specifications. Entergy believes that the Commission’s concerns may already be addressed by Reliability Standards INT-005 through INT-009.” Northern Indiana: “Northern Indiana contends that the NOPR’s discussion of INT-006-1 is unclear and confusing. It states that it does not understand what the Commission means by “validate” when the Commission proposes that reliability coordinators and transmission operators review and validate composite arranged interchanges. Northern Indiana also questions whether both reliability coordinators and transmission operators would be required to validate and approve the Tags and what the basis for approval would be. It questions what falls within the term “potential detrimental reliability impact,” what happens if a Tag is not validated within 20 minutes to the hour, and whether all schedules are canceled outright or passively approved.”	
FERC Order 693	INT-006-1	2009-03	Require reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink	Requirements to take action were added in INT-006 as R8 and R9. Requirements for the analysis are already addressed in IRO-008 R1 and TOP-008 R4.

Source	Standard No.	Project No	Issue	Response
			balancing authorities necessary transaction modifications before implementation.	
FERC Order 693	INT-006-1	2009-03	Include reliability coordinators and transmission operators as applicable entities.	This was addressed as part of adding requirements as described above in INT-006 as R8 and R9
FERC Order 693	INT-008-2	2009-03	Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.	Considered and clarified. All tasks assigned to specific entities, none of which are the IA.
FERC Order 693	INT-009-1	2009-03	Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.	Considered and clarified. All tasks assigned to specific entities, none of which are the IA.
FERC Order 693	INT-010-1	2009-03	Consider Northern Indiana's and ISO-NE's suggestions in the standards development process.	Language has been modified to make it clear these exemptions are for schedule changes which are then followed up by tagging changes. As such, this is an appropriate tool for IROLs, as it does not require tagging before schedule changes are made.
NERC Audit Observation Team	INT-006-2	2009-03	Does confirmed action mean direct action needs to be taken or, does confirmed action mean that a process has been put in place that will take action and, the entity agrees with such since they have employed the program.	SDT believes language has been clarified.
NERC/NAESB Coordination	INT-001-2	2008-12	NERC/NAESB Coordination • The SDT review the definitions of the following terms and coordinate with NAESB so that the definition of each term is consistent between NERC and NAESB: Interchange Schedule Interchange Transaction Interchange Transaction Tag (Tag) Request for Interchange Source BA Sink BA	Coordination to be undertaken if needed.
NERC/NAESB Coordination	INT-003-2	2008-12	NERC/NAESB Coordination • The SDT review the definitions of the following terms and coordinate with NAESB so that the definition of each term is consistent between NERC and NAESB: Interchange Schedule Interchange Transaction Interchange Transaction Tag (Tag) Request for Interchange Source BA Sink BA	Coordination to be undertaken if needed.
NERC/NAESB Coordination	INT-004-1	2008-12	NERC/NAESB Coordination • The SDT review the definitions of the following terms and coordinate with NAESB so that the definition of each term is consistent between NERC and NAESB: Interchange Schedule Interchange Transaction Interchange Transaction Tag (Tag) Request for Interchange Source BA Sink BA	Coordination to be undertaken if needed.
NERC/NAESB	INT-005-2	2008-12	NERC/NAESB Coordination • The SDT review the	Coordination to be undertaken if needed.

Source	Standard No.	Project No	Issue	Response
Coordination			definitions of the following terms and coordinate with NAESB so that the definition of each term is consistent between NERC and NAESB: Interchange Schedule Interchange Transaction Interchange Transaction Tag (Tag) Request for Interchange Source BA Sink BA	
NERC/NAESB Coordination	INT-006-2	2008-12	NERC/NAESB Coordination • The SDT review the definitions of the following terms and coordinate with NAESB so that the definition of each term is consistent between NERC and NAESB: Interchange Schedule Interchange Transaction Interchange Transaction Tag (Tag) Request for Interchange Source BA Sink BA	Coordination to be undertaken if needed.
NERC/NAESB Coordination	INT-007-1	2008-12	NERC/NAESB Coordination • The SDT review the definitions of the following terms and coordinate with NAESB so that the definition of each term is consistent between NERC and NAESB: Interchange Schedule Interchange Transaction Interchange Transaction Tag (Tag) Request for Interchange Source BA Sink BA	Coordination to be undertaken if needed.
NERC/NAESB Coordination	INT-008-2	2008-12	NERC/NAESB Coordination • The SDT review the definitions of the following terms and coordinate with NAESB so that the definition of each term is consistent between NERC and NAESB: Interchange Schedule Interchange Transaction Interchange Transaction Tag (Tag) Request for Interchange Source BA Sink BA	Coordination to be undertaken if needed.
NERC/NAESB Coordination	INT-009-1	2008-12	NERC/NAESB Coordination • The SDT review the definitions of the following terms and coordinate with NAESB so that the definition of each term is consistent between NERC and NAESB: Interchange Schedule Interchange Transaction Interchange Transaction Tag (Tag) Request for Interchange Source BA Sink BA	Coordination to be undertaken if needed.
NERC/NAESB Coordination	INT-010-1	2008-12	NERC/NAESB Coordination • The SDT review the definitions of the following terms and coordinate with NAESB so that the definition of each term is consistent between NERC and NAESB: Interchange Schedule Interchange Transaction Interchange Transaction Tag (Tag) Request for Interchange Source BA Sink BA	Coordination to be undertaken if needed.
Version 0 Team	INT-001-1	2009-03	R1 – Who tags dynamic schedules?	Specified now in INT-004.
Version 0 Team	INT-001-1	2009-03	Load PSE responsibility is new restriction	No longer restricted.
Version 0 Team	INT-001-1	2009-03	R1 - Too stringent	R1 has been modified since version 0. In this version, has been moved to INT-004 and only applies to Dynamic

Source	Standard No.	Project No	Issue	Response
				Schedules.
Version 0 Team	INT-001-1	2009-03	Lack of compliance	Comment unclear. Compliance to be rewritten in future revision.
Version 0 Team	INT-001-1	2009-03	More commercial problem than reliability	Comment unclear.
Version 0 Team	INT-001-1	2009-03	Onerous to BA's	Comment unclear.
Version 0 Team	INT-001-1	2009-03	Question on generation scheduling	Comment unclear.
Version 0 Team	INT-001-1	2009-03	R2.2 – 60 minute time frame questioned	Assuming this is regarding 60 minutes specified in INT-010, time is to allow after-the-fact tagging within a reasonable time frame to ensure reliability analysis tools have up-to-date information following emergency action.
Version 0 Team	INT-001-1	2009-03	Clarify tagging of reserves	Standard does not address tagging.
Version 0 Team	INT-004-1	2009-03	Use WECC criteria	Comment unclear.
Version 0 Team	INT-004-1	2009-03	Non-compliance based on %	Comment unclear. Compliance to be rewritten in future revision.
Version 0 Team	INT-004-1	2009-03	Suggested non-compliance levels	Comment unclear. Compliance to be rewritten in future revision.
Version 0 Team	INT-004-1	2009-03	Need to address tag curtailment	Comment unclear.
Version 0 Team	INT-004-1	2009-03	Replace TSP with TOP	Comment unclear. Standard no longer refers to TSP.
VRFs Team	INT-001-1	2009-03	R1, 1.1, 2, 2.1, 2.2 – commercial and administrative	SDT disagrees on R1, and has moved to INT-004. SDT agrees R2 is not needed,
VRFs Team	INT-003-1	2009-03	R1, 1.1, 1.1.2, 1.2 – commercial and administrative	SDT disagrees, and has moved to INT-009.
VRFs Team	INT-004-1	2009-03	R2, 2.2, 2.3 – commercial and administrative	SDT disagrees, and has included in INT-006 now.
VRFs Team	INT-005-2	2009-03	R5 – administrative	SDT disagrees, and has included in INT-006 now.
VRFs Team	INT-007-1	2009-03	R1, 1.1, 1.3, 1.3.1, 1.3.2, 1.3.3, 1.3.4, 1.4 – administrative	SDT disagrees, and has incorporated into INT-006.
VRFs Team	INT-008-2	2009-03	R1.1.1 & 1.1.2 – commercial and administrative	SDT disagrees, and has incorporated into INT-006.
VRFs Team	INT-010-1	2009-03	R1 & 3 – administrative	SDT disagrees.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Period Open

November 10ï December 11, 2009

Now available at: http://www.nerc.com/filez/standards/Project2008-12_Coordinate_Interchange_Stds_Modifications.html

Project 2008-12: Coordinate Interchange Standards

The Coordinate Interchange Standard Drafting Team is seeking comments on the following proposed standards **until 8 p.m. EST on December 11, 2009**:

- INT-004-3 — Dynamic Schedules
- INT-006-4 — Evaluation of Interchange Transactions
- INT-009-2 — Implementation of Interchange
- INT-010-2 — Interchange Initiation and Modification for Reliability
- INT-011-1 — Interchange Coordination Support

The drafting team has also posted a number of standards it proposes to retire as part of the project:

- INT-001-3 — Interchange Information
- INT-003-2 — Interchange Transaction Implementation
- INT-005-3 — Interchange Authority Distributes Arranged Interchange
- INT-007-1 — Interchange Confirmation
- INT-008-3 — Interchange Authority Distributes Status

The comment form details the changes to the standards and explains the approach taken by the drafting team. Some requirements from the standards proposed for retirement were moved to the proposed standards. Also posted is a table of identified issues with the Coordinate Interchange standards and analysis from the drafting team.

Instructions

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/Project2008-12_Coordinate_Interchange_Stds_Modifications.html

Next Steps

The drafting team will draft and post responses to comments received during this period.

Project Background

The purpose of this project is to revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator, or user of the bulk power system and not to a tool used to coordinate interchange; to address the Interchange Subcommittee concerns related to the Dynamic Transfers and Pseudo-Ties; to address previously identified stakeholder comments and applicable directives from Federal Energy Regulatory Commission (FERC) Order 693; to define communications on reloading interchange transactions due to different operational conditions; and to bring the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines, and Uniform Compliance Monitoring and Enforcement Program.

The project will be addressed in two phases. The first phase will address issues related to the Interchange Authority function and the relationship with electronic tagging (e-Tag), as well as FERC's directives from Order 693. The second phase will address issues related to Dynamic Transfers in detail, as well as backup plans.

Applicability of Standards in Project

Balancing Authorities
Reliability Coordinators
Transmission Operators
Purchasing-Selling Entities
Transmission Service Providers

Proposed Glossary of Terms Change

Interchange Coordination (new definition)

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.

Individual or group. (30 Responses)
Name (15 Responses)
Organization (15 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
Question 1 (23 Responses)
Question 1 Comments (30 Responses)
Question 2 (27 Responses)
Question 2 Comments (30 Responses)
Question 3 (27 Responses)
Question 3 Comments (30 Responses)
Question 4 (27 Responses)
Question 4 Comments (30 Responses)
Question 5 (27 Responses)
Question 5 Comments (30 Responses)
Question 6 (26 Responses)
Question 6 Comments (30 Responses)
Question 7 (26 Responses)
Question 7 Comments (30 Responses)
Question 8 (26 Responses)
Question 8 Comments (30 Responses)
Question 9 (26 Responses)
Question 9 Comments (30 Responses)
Question 10 (25 Responses)
Question 10 Comments (30 Responses)
Question 11 (26 Responses)
Question 11 Comments (30 Responses)
Question 12 (25 Responses)
Question 12 Comments (30 Responses)
Question 13 (25 Responses)
Question 13 Comments (30 Responses)
Question 14 (24 Responses)
Question 14 Comments (30 Responses)
Question 15 (22 Responses)
Question 15 Comments (30 Responses)
Question 16 (23 Responses)
Question 16 Comments (30 Responses)
Question 17 (0 Responses)
Question 17 Comments (30 Responses)

Individual
Jon Kapitz
Xcel Energy
Agree
Agree
Consider including the term “compatible” as part of the description.
Agree
Disagree
It is unclear as to whether an entity must still self report in cases where Interchange

Coordination is nonfunctional. Do you have a statistic as to how often this occurs? So, if OATI goes down for an hour, must all EI entities self-report?
Agree
However, INT-009 R2 has “or alternate control process” in parentheses. Believe this should be deleted. ACE is a measurement for compliance that may be used for control purposes. It is up to the entity to comply with the remaining NERC standards, including performance. The entity may be able to accomplish that without incorporating the NSI into their control process. The requirement should only state that the term be used in the BA’s ACE, though this may be unnecessary as ACE is defined in other standards.
Agree
Disagree
This is predicated on an electronic platform. What occurs if the electronic platform is not available? Is a manual process taken into account? If a manual process had to be implemented, the 1 minute time frame would not be reasonable.
Agree
We agree with specifying the minimum criteria for which AI can be denied; consider adding language similar to INT-010 R4.5 “Any real-time reliability concern related to a specific Arranged Interchange, provided that concern is supported by evidence.”
Disagree
This question implies that the BA can choose to not approve the Reliability Adjustment. What constitutes the ability of a BA to support the magnitude of Interchange?
Agree
Agree
Agree
Disagree
Disagree
Disagree
INT-009 R2 has “or alternate control process” in parentheses. Believe this should be deleted. ACE is a measurement for compliance that may be used for control purposes. It is up to the entity to comply with the remaining NERC standards, including performance. The entity may be able to accomplish that without incorporating the NSI into their control process. The requirement should only state that the term be used in the BA’s ACE, though this may be unecessary as ACE is defined in other standards. INT-011-1 R1.1 refers to a Load Balancing Authority. Should this be Sink Balancing Authority? With respect to requiring an entity to be able to “electronically” perform functions, consider the need to state that is must be compatible with the Interchange Coordination tools. In general: • the standards are wordy and written in a manner that is difficult to understand. • Is there an ability to use a manual process in lieu of an electronic system if the Interchange Coordination tools are not available? If so, do the requirements need to cover this situation?
Group
Functional Model Working Group
Jim Cyrulewski, Chairman
Disagree
The Functional Model Working Group (FMWG) does not agree with removing the IA from the NERC standards. The FMWG would like to make clear what is meant with the statement "... assigning those functions to the Sink Balancing Authority directly would not conflict with the functional model" The FMWG has clearly articulated in the Functional Model Report and in the associated Functional Model Technical Report that the Functional Model does not in any way presume to direct the Registration process associated with NERC Reliability Standards. The Functional Model itself identifies independent tasks that can be accomplished by independent entities. The IA is one such set of independent tasks. That set of tasks has been and continues to be a required “function”. The FMWG wants to make clear that the IA function is regarded as a critical reliability function and should not be removed. Regarding registration, the FMWG does not regard registering NERC-registered Balancing Authorities (BA) as IAs to be in conflict with the Functional Model. The FMWG would note that “Each BA may be an IA; but not every IA needs

to be a BA." There is a significant difference between the two ideas. It should be noted that none of the NERC and FERC-approval functional entities are "actual entities" until a corporate entity registers (or is registered) by NERC to comply with the standards written to the respective functions. The SDT misconstrues the issue. The FMWG agrees with the NERC Regions' default position is that if no entity registers as an IA, then the sink BA will be held responsible for the IA requirements. The lessons learned when NERC was operating under voluntary policies was that if a set of functions can be served independently; ultimately some entity will fill that position. The fact that the IA functions have the potential to be served by a corporate entity that does not need to fill all of the NERC BA requirements indicates the need to separate the tasks from the BAs. That does not mean that in the absence of such a corporate entity, that the BAs (as a default position) cannot be assigned to be compliant with the IA tasks. To return to a blanket assignment of the IA tasks to the BA is to ignore the lessons of the history of NERC. Lastly, there is no issue with requiring BAs to comply with the tasks defined for the IA. The original confusion was/is with the concept that a delegated (non-registered) third-party is providing the IA functions. However, to eliminate the reference to IA and to place the same tasks under the BA does nothing to rectify that issue/non-issue. However, the elimination of IA will mean that in the future when a corporate entity does want to register to do those tasks that entity will by necessity have to be a BA. Thus it can be seen that eliminating IA is not the same as requiring BAs to comply with the IA functions.

Disagree
Disagree
Disagree
Disagree
Agree
Disagree
Disagree
The reliability issue is whether or not the Interchange is approved or denied. The reasoning for that decision is not a reliability issue as much as it is a business issue.
Agree
Disagree
.
Disagree
Disagree
Disagree
Agree
PLEASE NOTE THAT THE FMWG IS SUBMITTING COMMENTS ONLY TO QUESTION 2 The survey form does not provide the option to deselect the agree/disagree entry once it is checked. All other responses should really be NO RESPONSE.
Individual
James Starling
South Carolina Electric and Gas

Disagree
SCEG believes the Confirmed Interchange profile is not required to be checked out hourly, but upon changes in schedules
Group
Northeast Power Coordinating Council
Guy Zito
Agree
It is not clear what the second phase is. Backup plans only appear in BAL-005.
Disagree
This does conflict with the Functional Model. This may create a problem if and when an entity steps forward to register as the IA and perform the IA functions. We suggest the SDT consider reverting back to the existing applicability and assign this to the IA, but specify that given there are no entities registered as the IA and the default is the sink BA, all BAs are required to perform the IA function and hence need to register as one.
Disagree
We do not agree that this defined term is necessary; the concept can be described in the purpose without creating a new definition. Suggest the SDT coordinate the development of the Interchange Coordination definition with the Functional Model Working Group, which in its FM Version 5 has developed a definition for Interchange and Interchange Coordinator. Having different definitions for similar terms within the NERC documents tends to create confusion.
Disagree
Please see the comments to Question 2 above. Standards should be written to drive proper behaviors, not to specify the equipment and staff capabilities. The latter requirements belong to Organization Certification Requirements. (1) The term “desire to” is not needed as it makes the standard not measurable. Suggest to remove it from R1 and R3. (2) The majority of this standard deals with capability, not behavior. Suggest moving the requirements of this standard to Organization Certification Requirements.
Disagree
All transactions must be agreed to under any situations to ensure reliability. The proposed footnote and the added phrase appear to be adequate. No one should be found non-compliant if the hardware/software is not available to support these tasks, but we are not sure that these footnotes are the best way to achieve that goal. Can statements be made in the Measures and Compliance to address this?
Disagree
The mandate in the original set of standards has been missed. INT-001 establishes the mandate that special case interchange be explicitly assigned to some entity. In the case of Inadvertent Interchange payback, such payback can be initiated by either BA that has an accumulation, but R2.2 clearly mandates that the responsibility falls on the sink BA. The SDT should raise the issue of whether or not Inadvertent Interchange is a reliability issue or a business issue. Where INT-001 relates to a single Interchange, INT-009 relates the sum of all Confirmed Interchange and to the fact that the net of Confirmed Interchange only goes into the ACE equation. These are two distinct functions. INT-009 recognizes that NET Interchange is done among adjacent BAs. INT-001 assigns responsibility to BAs that may or may not be adjacent.
Agree
Disagree
INT-006 was designed to mandate the distribution of information. There is a possibility that an IA could collect approvals/denials and not inform anyone of the results. Hence there is a need to mandate that the data be distributed. If one agrees that the data be distributed, one could argue that there is a need to define the time-frame. The NAESB Tables bind the analysis and response times. The Timing Tables in INT-006-3 create a window of 1 minute between when confirmations are mandated and when they are implemented. Given the fact that it takes some time to change the values going into a BA's ACE equation there is not a lot of time to allocate. The one-minute period is consistent with the Tables. With respect to the specific requirements of R1, we agree with R1.1, but do not understand how R1.2, R1.3 and R1.4 apply to the general statement in R1

that addresses distributing 'a request' within a minute of its receipt. For example, if the request has not yet been distributed – how can it have been denied (R1.4)? We do not agree with R7.2, 7.3, 7.4. The general text of R7 is to requiring notification of whether or not AI was transitioned to Confirmed. The language of R7.2 implies something has already been distributed, yet the purpose of R7 is the actual distribution. If 7.3 or 7.4 are true the notification should be that is WAS NOT transitioned to Confirmed. If the intent is to only require notification of AI that was Confirmed, then the language of R7 needs to be modified to reflect that intent.
Disagree
The reliability reasons for denying an interchange request should be provided. With respect to economic markets, the reasons listed are appropriate, but the timing of their applicability should be reconsidered. For example, each market has submittal deadlines. Until those submittal deadlines have been reached, the system conditions are not fully understood and no action can be taken to 'deny' a request. For example, if a new interchange request, Request A, would result in the flow on an interface to exceed the transfer capability – another interchange request, Request B, may be submitted that would net against Request A. There is no reliability issue that needs to be addressed until the market deadline has passed.
Agree
Disagree
The phrase 'shall not transition an Arranged Interchange to Confirmed Interchange' appropriately utilizes the currently defined terms, but it is not clear what action should be taken – should there be a transition to a state of denied?
Disagree
(1) Potentially required is not measurable. (2) There is redundancy in R8 with TOP-005-2 R2. Also, R8 should be reworded for clarity. Suggest "Each Transmission Operator shall notify the Sink Balancing Authority(ies) when interchange schedules need to be modified to prevent a violation of a SOL or IROL." (3) There is redundancy in R9 with IRO-001-1.1 R9 (all issues), IRO-009-1 R3 (Day Ahead IROLs), and IRO-004-2 R1 (the BA must follow directives). Also, R9 should be reworded for clarity. Suggest "Each Reliability Coordinator shall notify the Sink Balancing Authority(ies) when interchange schedules need to be modified to prevent a violation of an IROL." Additional concerns are with respect to existing markets where submittal deadlines allow new interchange requests to occur up to 'near real-time'. In that type of market environment an estimate of the net interchange would be available on a day-ahead basis but there is no expectation of taking action to modify specific interchange requests on a day-ahead basis.
Disagree
(1) The requirement assumes that it defines the complete set of exemptions. However, the IRO and TOP standards do a better job by mandating that the RC and TOP take actions for IROLs not just during an event but also if an event is anticipated. (2) This requirement is redundant with IRO-009-1 R4. What about when an adjustment is made because of failed checkout, or the economics of a transaction in a market?
Disagree
The word "composite" is confusing. Does it mean the net BA to BA interchange, or individual BA to BA interchange? The default when there is a disagreement is that the BAs must check each Interchange Schedule and not just Net Interchange. Does special consideration need to be given in the requirements (or only the Measures and Compliance) for known and planned hardware/software outages that could impact this process for more than one hour?
Disagree
No comments.
Disagree
As provided in Q9, Q12 and Q13 above, there may be special 'interpretation' required to ensure these requirements, as written, do not conflict with some FERC approved markets.
In INT-004-3 R1, the term "Load-serving, Purchasing-Selling Entity" is used and can cause confusion by making this standard appear to apply to Load-serving Entities as well as Purchasing-Selling Entities. A Purchasing-Selling Entity should have to adhere to these requirements whether or not it is serving retail load. "Load-serving" should be stricken from this requirement. There are several places where the Load Balancing Authority is used. Why is this term used instead of Sink Balancing Authority? INT-004: Why does an AI created based on the maximum MW value of a Dynamic Schedule never need to be modified? This seems to allow everyone to put in a maximum value and leave it unchanged for the duration of the interchange. INT-006: The term IA still exists in the timing tables. Also, the table requires distribution of Late and ATF AIs when the language in the requirements is only applicable to on-time AI. INT-009: The addition of the phrase 'and maintain the generation-to-load balance' in the Purpose does not seem to be consistent with the requirements of the standard; there are no requirements related to this action. Suggest removing. INT-010: The purpose of INT-010 indications that some Interchange Schedules should be exempt from compliance with 'other Interchange Standards'.

The requirements within INT-010 do not seem to be consistent with this purpose. INT-011: The Reliability Coordinator is in the Applicability section but is not mentioned in the requirements.
Individual
Angela P. Gaines
San Diego Gas & Electric
Agree
Agree
At present, there appears to be no issues with removing IA from these standards. However, in doing so, an expanded or new definition of BA should be developed that incorporates the functions originally assigned to the IA to insure clarity within the INT standards themselves, as well as any other standard where the BA adopts the IA functionality.
Agree
Agree
Disagree
There appears to be no clear reason as to why the footnoted phrase applies to similar requirements in one standard and not another. Therefore, the phrase should apply to similar requirements in all of the INT standards.
Although the term, "Load Balancing Authority" appears in the proposed new standard INT-011-1, and is also used in the approved Reliability Standard IRO-006-3, there is no definition of this term in the Glossary of Terms Used in Reliaibility Standards. A definition should be created. The use of the term, "Confirmed Interchange" seems to be different than the definition currently listed in the Glossary of Terms Used in the Reliability Standards. In addition, the present term still refers to the IA. A new or revised definition of Confirmed Interchange is necessary.
Group
SERC OC Standards Review Group
Jim Case
Agree
Agree
We completely agree: The IA should never have been coined as a term of art in NERC discussions.
Agree
Disagree
While the SERC OC Standards Review Group agrees that this list of tasks is appropriate and sufficient to arrange interchange, we believe requirements to have “capabilities” more properly belong in certification and this standard should be eliminated. Currently, only Reliability Coordinators (RCs), Balancing Authorities (BAs) and Transmission Operators (TOPs) must be certified. We recognize that eliminating this standard may require additional entities to be certified
Disagree
We agree with the intent of the language and the standards to which it is applied, but it needs to be explicitly in the requirements. Footnotes are not requirements.
Agree
Agree

Disagree
The SERC OC Standards Review Group cannot determine a reliability reason to have either R1 or R7. Further, we believe Requirements R1 and R7 as written are unclear, unmeasureable, and unenforceable.
Disagree
While we agree with R2.1 and reasons 1 and 3 of R3.1, the TSP cannot know projected system conditions as suggested in reason 2 of R3.1. This amounts to a preemptive TLR before the real time flows materialize.
Disagree
We generally agree with the intent of this new requirement. However, in the case of a co-owned unit serving load in two BAs via Confirmed Interchange, if that unit tripped, this requirement appears to saddle the Source BA with deleterious CPS and DCS results. It would seem that the Sink BA would be required to approve a curtailment, regardless of ramp, in this case. This situation appears to be more complicated than could be resolved with this requirement.
Agree
Disagree
How are the RCs and TOPs supposed to be able to know in advance of the real time flows exactly how many MWs of curtailment would be required in the case of a projected SOL or IROL exceedance? To what level of accuracy must these projections be made? What happens if the RC or TOP projects the wrong level of curtailment? Basically we don't feel that FERC's directive can be addressed without seriously damaging the energy market as we know it today.
Agree
Disagree
We agree with the SDT's position. However, we assert that ramps should be verified to be identical as well.
Disagree
Agree
In questions 9 and 12, the SDT appears to essentially require a preemptive TLR anywhere from hours to a day in advance of the materialization of real time flows in excess of the real time capability of the transmission grid. This would inappropriately reduce the liquidity and optionality afforded by the current physical rights of tariffs for transmission service.
The SDT needs to review all INT standards, particularly INT-004-3, in regards to the applicability of the entities for those requirements. "The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Individual
Steve Alexanderson
Central Lincoln
INT-004-3 R1 introduces a new entity type called the "Load serving, Purchasing-Selling Entity." This entity was left off the applicability list for the standard, and does not yet exist in the functional model or the registry criteria. Who exactly does R1 apply to?

Group
Midwest ISO
Nicholas Browning
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Language should be added to define that the only responsibility to validate adjacency of a scheduling path (in 2.1) to a BAs own interconnection. Similarly, each TSP (in 3.1) will only be responsible to validate adjacency of a transmission path only to the extent of its interconnecting TSPs.
Disagree
Language should be changed to On-Time Reliability Adjustment Requests. "Late" (and even past-) requests MAY still be approved, but should not be a NERC defined "Must". E-Tag specifications may be changed to passively-APPROVE reliability adjustment requests to accommodate this standard, but that should only be automatic if the request is On-Time.
Disagree
Language is needed to more accurately define direct-current tie Operating Balancing Authority, and its communication role, as that role may not be otherwise designated in the e-Tag's approval path. As well, a DC portion of the transmission path may not be designated on an e-Tag, and may be completely unknown to the Sink Balancing Authority.
Agree
Agree
Disagree
Midwest ISO "agrees" to the intent of the requirement and that no default procedure is necessary. The requirement language should remove the words "No more than one hour". Scheduled interchange may be agreed to prior to that OH-1 along with other hours of static MW flow, for example. If this previously agreed-upon interchange schedule has not changed, no further communication should be needed.
Disagree
Disagree
Individual
Kasia Mihalchuk
Manitoba Hydro
Agree
Agree
Agree
Agree

Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Disagree
Disagree
Disagree
Individual
Darcy O'Connell
California ISO
Disagree
The present INT Reliability Standards could use some “polishing” to eliminate redundancy and consolidate some Requirements, however, this SDT initiative seems to be primarily/solely(?) focused upon eliminating the IA function and responsibility, which is not appropriate, and which the CISO does NOT support.
Disagree
The IA IS an actual entity and must be, as Interchange management tracking tools (like the Western Interchange Tool or WIT for the WECC) are inanimate objects, and not capable of cognitive thought. The responsible party (IA) is the owner or operator of the tool, not the tool itself. The IA uses ITS tools to accomplish and fulfill its IA functional model role. In the West, the IA is the RRO, WECC, by way of 36 bilateral contracts. The California ISO believes the proposed NERC INT Standard changes advance substantial changes to the present Interchange Schedule standards and move away from the central coordinating responsibility of the Interchange Authority (IA), in our case WECC, which uses the WIT as the IA monitoring tool. Each of the BAs within the WECC helped develop and pay for development of the WIT. This IA function has worked well over the past two years, with clear lines of authority and responsibility, as documented in the IA contract with the RRO. When asked “what changes” with the SDT draft revisions, the answers to hardware? Software? Liability? Were all 3 nothing” responses. As such, we would oppose any movement away from the defined IA role, absent some substantive justification. WECC (as our IA in the West) and the WIT are the Interchange Authority and definitive keeper of all Implemented Interchange documentation, respectively. The Interchange Authority is an entity, and cannot be software. WECC was selected as the IA for the West and uses WIT as its IA tool. The CISO would not support movement away from IA authority towards dispersed Sink BA authority. You cannot have 37 BAs all responsible in the role of an IA to tell the other 36 what to do. Arranged Interchange must be mutually agreed upon and checked out, with oversight by the RRO as the IA. At present, the CISO has an IA services contract in place with WECC for this purpose. We strongly support use of the WECC WIT by all WECC entities. These proposed significant NERC Standard changes are contrary to the concept of the IA, and thus to the WIT as the definitive repository for arranged interchange. Further, it seems like an inefficient use of time to revisit the issue of the IA definition and role, especially so given the fact that this issue was previously resolved within the West by the WECC Interchange Scheduling Committee and the WECC Board, establishing the WECC, our RRO as our IA for the West. All 37 BAs negotiated and entered into IA contracts with WECC in this IA capacity accordingly in

December 2008. The CISO supported and continues to support this convention, the present NERC IA definition and has been very pleased with the WIT as the WECC IA Tool as the definitive source of documentation for checked out NSI and NAI. With so many other critical matters before us, it seems an inefficient use of time to reopen a construct that is serving us well.
Disagree
Interchange coordination is inherent in the pre, RT and ATF checkout processes facilitated by the IA and the WIT tool in the West. Please see comment for Question #2.
Disagree
There are problems in this standard: R1.1 - "Load Balancing Authority" should be replaced with the defined term "Sink Balancing Authority" as defined in the NERC Glossary. R2.3 – Validate Requests for Interchange (RFI) section is missing the Energy Product validation used to determine if additional reserves are needed and is a valid reason to deny a tag. R2.4 – "Validate request to modify Interchange" is silent on the entities that have the rights/requirements for approval or denial. Curtailments should only require Source and Sink to approve that type of modification. Does "modify" really mean a market and/or reliability adjust? If so there needs to be a change to the terminology. R2.5 – Should indicate which entities are distributed the RFI. R2.6 – Should indicate which entities are distributed the RFI.
Disagree
Agree
Agree
Agree
Agree
An RFI missing the valid product Energy Code is also a reason for denial.
Agree
Agree
Disagree
R8 – the Requirement to have a TO notify a Sink BA of potential problems with modifications should be covered in the IRO Standards and not the Arranged Interchange Standards. R9 – The Requirement to have an RC notify a Sink BA of potential problems with modifications should be covered in the IRO Standards and not in the Arranged Interchange Standards.
No comment
No comment
Agree
Retain IA role and function. Retain Arranged and Implemented Interchange.
Agree
SDT draft change run counter to present IA contracts in the West, negotiated and entered into in good faith.
INT-004-3 Comments: In the WECC, the effective date is based on the "First day of the first calendar quarter following the date this standard is approved by applicable authorities." R1.1 – The term "Load Serving, Purchasing-Selling Authority" should be changed to "Load-Serving Entity" as defined in the NERC Glossary. There is a question pertaining to "Reloading Transactions" in Question #7 of the accompanying questionnaire. INT-006-4 Comments: R1 – Appears to be missing the RFI distribution to the PSE. R2.1 – Missing valid energy product code is a valid reason for denial. R4 – Direct-current Tie Operator or Direct-Current Tie Operating Balancing Authority should be defined and added to the NERC Glossary. R8 – The requirement to have a TO notify a Sink BA of potential problems with modifications should be covered in the IRO Standards and not the Coordinate Interchange Standards. INT-009-2 Comments: Requirement numbering (R numbering and R sub-numbering) needs to be consistent between this and other INT Standards. R2 – The NERC definition defines the Net Interchange Schedule, it does not define Net Scheduled Interchange, although many use the terms interchangeably. What is meant by the use of the word "term"? INT-010-2 Comments: There is a need to identify the default entity that creates the tag in requirements R1-R3 as the Load Serving Entity. INT-011 Comments: R1.1 – "Load Balancing Authority" should be replaced with the defined term "Sink Balancing Authority" as defined in the NERC Glossary. R2.3 – Validate Requests for Interchange (RFI) section is missing the Energy Product validation used to determine if additional reserves are needed and is a valid reason to deny a tag. R2.4 – "Validate request to modify Interchange"

is silent on the entities that have the rights/requirements for approval or denial. Curtailments should only require Source and Sink to approve that type of modification. Does "modify" really mean a market and/or reliability adjust? If so, there needs to be a change to the terminology. R2.5 – Should indicate which entities are distributed the RFI. R2.6 - Should indicate which entities are distributed the RFI.
Group
PPL Energy Plus
John Cummings
Agree
Disagree
The definition of "Interchange Coordination" appears only in INT-011 and it needs to be in all INT standards. Further, the definition should specify that a tool cannot be responsible for performance: registered entities are responsible for performance and the responsible entity required to carry-out such performance should be stated clearly in each standard.
Agree
Disagree
Footnotes 1&2 in INT-004-3 relieve all parties from the responsibility of assuring interchange takes place on the electric grid under poorly-defined circumstances. PPL believes removing responsibility for interchange under any circumstances places the reliability of the grid at great risk should critical software or hardware fail . A FAX, phone or other backup should be required to effect performance and this footnote should be deleted. This same footnote appears in the following standards and should be removed from all: INT-006-4 Footnotes 2, 3, 5, 7, 8, 9, &10 INT-010-2 Footnotes 1, 2 & 3 INT-011-1 Footnotes 1, 2 & 3
Disagree
Unless dynamic schedules are tagged and identified in the Coordinated Interchange software that is used to develop the net schedule, they will never be curtailed using same software. This means all other schedules have a lower priority than Dynamic schedules and this should not be the case. We are not convinced that INT-009-2 R2 adequately conveys the requirement that dynamic schedules be tagged and tracked in curtailment software. Further, under R2.2: the word "Plus" is used to describe inclusion of a number (the Dynamic schedule) which may or may not be POSITIVE. It may be best to use a word other than "Plus" such as "including" or "summation" in order to provide clarification and accuracy.
Disagree
**Please re-insert R2 from INT-004-2 that requires a release and reload of interchange that has been curtailed. Please assure that in all cases, the PSE's are kept informed of all curtailments and reloads. **R1: Loads with dynamic schedules are still the responsibility of the Sink BA who should be included as a responsible party. The old requirement that Sink BA's arrange for dynamic schedules for Joint Owned Units (JOUs) and inadvertent payback is implied, but not stated. Please clearly state that the entity responsible for Arranging Dynamic Interchange for JOUs and inadvertent payback is the Sink BA in the new standards. **R2.3 requires the PSE to modify the dynamic schedule for reliability concerns communicated by the RC/TOP to the PSE's. However, it does not appear that these INT standards require the RC/TOP to notify the PSE that a reliability concern exists and that the associated modification(s) or reload(s) must take place. Please insert such notification to the affected PSE(s) into the requirement.
Disagree
**R1: The reasoning behind R1.3 (less than the three-minute time) is not clear. In fact, R1.2 and R1.3 seem to be at odds with one another. Would the CI SDT please review the concepts under R1 and clarify the wording of sub-requirements 1.2 and 1.3? **R3.1 Item 1): Should "remaining for the TSR" be "remaining on the TSR"? **R3.1 Item 3): This requirement needs to allow for situations where the physical transmission path is intact, but a software tool does not have the right database model. In this case, a responsible entity should be allowed the discretion to allow the Interchange to flow regardless of the underlying software model. **R6: Sub-requirements 6.1 through 6.3 include a logical "and". Should this be a logical "or"? **R7: The PSE (or other party originating Arranged Interchange) should be included in the list of parties notified of transition from Arranged to Confirmed. Please correct this omission.
Disagree
**R3.1 Item 1): Should "remaining for the TSR" be "remaining on the TSR"? **R3.1 Item 3): This requirement needs to allow for situations where the physical transmission path is intact, but a software tool does not have the right database model. In this case, a responsible entity should be allowed the discretion to allow the Interchange to flow regardless of the underlying software model.

Disagree
**R6: Sub-requirements 6.1 through 6.3 include a logical “and”. Should this be a logical “or”? **R7: The PSE (or other party originating Arranged Interchange) should be included in the list of parties notified of transition from Arranged to Confirmed. Please correct this omission.
Disagree
**This standard needs to apply to Reliability Coordinators if the PPL-proposed R5 (below) is included. **There may be occasions when a BA or TSP will not respond to a PSE request under R4. Because of possible non-response by the BA and/or TSP, R5 should be added to require RC’s to respond to a RFI from PSE’s (or possibly requests from all non-BA’s or non-TSP’s).
The CI SDT should be commended for their tremendous efforts to correctly assign responsibilities to the entities involved in Coordinated Interchange. PPL offers the following comments to support the CI SDT in their endeavors. 1)Since INT-011 describes what might be the first step in the sequence of events to establish Interchange, the rest of the standards should be numbered sequentially (i.e. INT-012, etc.). 2)The CI SDT needs to be prepared for the situation where all new standards are not approved by the FERC or all old standards are not approved for retirement by the FERC. We recognize that this is not the intent, but it remains a possibility. A solution may be to link the retirements to the approvals or combine the retirement into the new approved standard etc. INT-004-3 Dynamic Schedules Please re-insert R2 from INT-004-2 that requires a release and reload of interchange that has been curtailed. Please assure that in all cases, the PSE’s are kept informed of all curtailments and reloads. R1: Loads with dynamic schedules are still the responsibility of the Sink BA who should be included as a responsible party. The old requirement that Sink BA’s arrange for dynamic schedules for Joint Owned Units (JOUs) and inadvertent payback is implied, but not stated. Please clearly state that the entity responsible for Arranging Dynamic Interchange for JOUs and inadvertent payback is the Sink BA in the new standards. R2.3 requires the PSE to modify the dynamic schedule for reliability concerns communicated by the RC/TOP to the PSE’s. However, it does not appear that these INT standards require the RC/TOP to notify the PSE that a reliability concern exists and that the associated modification(s) or reload(s) must take place. Please insert such notification to the affected PSE(s) into the requirement. INT-006-4 Evaluation of Interchange R1: The reasoning behind R1.3 (less than the three-minute time) is not clear. In fact, R1.2 and R1.3 seem to be at odds with one another. Would the CI SDT please review the concepts under R1 and clarify the wording of sub-requirements 1.2 and 1.3? R3.1 Item 1): Should “remaining for the TSR” be “remaining on the TSR”? R3.1 Item 3): This requirement needs to allow for situations where the physical transmission path is intact, but a software tool does not have the right database model. In this case, a responsible entity should be allowed the discretion to allow the Interchange to flow regardless of the underlying software model. R6: Sub-requirements 6.1 through 6.3 include a logical “and”. Should this be a logical “or”? R7: The PSE (or other party originating Arranged Interchange) should be included in the list of parties notified of transition from Arranged to Confirmed. Please correct this omission. INT-009-2 Implementation of Interchange R2.2: the word “Plus” is used to describe inclusion of a number (the Dynamic schedule) which may or may not be POSITIVE. It may be best to use a word other than “Plus” such as “including” or “summation” in order to provide clarification and accuracy. INT-010-2 Initiating and modifying Interchange for Reliability This standard needs to apply to Reliability Coordinators if the PPL-proposed R5 (below) is included. There may be occasions when a BA or TSP will not respond to a PSE request under R4. Because of possible non-response by the BA and/or TSP, R5 should be added to require RC’s to respond to a RFI from PSE’s (or possibly requests from all non-BA’s or non-TSP’s). INT-011-1 Interchange Coordination Support (i.e. electronic tools to support interchange). R1: Please add wording to indicate that the Sink BA’s must be responsible for providing Arranged Interchange if a PSE cannot author an etag.
Individual
Louise McCarren
WECC
Agree
Agree
WECC supports the removal of the IA from the INT standards. WECC agrees that in the currently effective Functional Model and INT standards, the IA is not an actual entity (user, owner or operator of the bulk electric system) and strongly supports the direction of the CISDT. Corresponding edits to other standards, such as CIP-002 through CIP-009 and IRO-010, should also be made to reflect the removal of the IA.

Agree
Disagree
WECC does not have a comment on the tasks performed by the BAs, PSEs and TSPs. However, this standard lists the Reliability Coordinator in the Applicability section but there are no tasks, requirements or measures in the standard applicable to the RC. The RC should be removed from the applicable entity list. Furthermore, compliance measures and compliance monitoring information need to be identified in order for functional entities to fully understand what they will be responsible for and comment accordingly.
Disagree
WECC agrees with the general concept that such events should be considered as special cases in the INT standards. However, performance metrics should be associated with all of the requirements in the INT standards so compliance and the functional entity clearly understand their obligations. Specifically, with respect to degradation due to coincidental, accidental or malicious causes, a specific measure, such as a system availability threshold, should be identified.
Agree
Agree
Disagree
WECC agrees with the concept but the language is wordy and difficult to follow. Specifically, the CI SDT should consider whether the “and” is appropriate in this context. For example, 1.2 and 1.3 appear contradictory – how can an Arranged Interchange not transition to Confirmed Interchange and still have notice of the Arranged Interchange being transitioned to Confirmed Interchange. Perhaps a flow chart would be easier to understand. Also, emergency transactions can be entered in real-time or after the fact and may need to be specifically addressed. This also needs to be clarified. In general, however, WECC agrees that as long as the transaction is delivered when it was scheduled there is not a reliability issue.
Disagree
WECC does not have a comment on INT-006 base requirement R2. However, sub-requirement R2.1 is difficult to monitor for compliance. There is no way to measure or document whether a BA “expects” or “does not expect” to be capable of supporting the Interchange. Furthermore, R2.1 does not appear to enhance reliability. BAs have adequate authority to deny a tag for reliability and validity reasons without inclusion of this sub-requirement.
Agree
Agree
Disagree
Requirement R9 is not necessary, as the RCs have enough latitude in the existing IRO-004 to mitigate problems identified in the next day studies results. This requirement should not create redundancy or confusion with IRO-004.
Disagree
The RC needs to have the ability to use all its available tools to determine how to mitigate any potential issues on the BES. This requirement appears to unnecessarily limit the use of a Reliability Adjustment Request, and thus restrict the RCs use of this tool.
Disagree
this requirement should NOT be modified. It is appropriate as is.
Disagree
No requirements are missing.
Disagree
Not aware of any conflicts.
WECC is generally in favor of the revised INT Standards that are currently posted on the NERC Web site for a 45-day comment period, especially the removal of the IA from the INT standards. WECC recognizes that individual members within WECC may submit comments in opposition of this, and respects the rights of those members to differ with WECC’s opinion Another general comment is that the compliance measures and data requirements need to be clearly defined in order for entities to fully understand their responsibilities, and for Regional Entities to understand and develop a reasonable audit approach for the standards. WECC thanks the CISDT for the opportunity to provide comments.
Individual
Kirit Shah

Ameren
1. The SDT should address if pseudo-ties should be shown so that they can be included in reliability tool (IDC) analysis. If they are to be excluded, please add a footnote stating it. 2. In INT-10, R4, an RFI acronym is used that is not defined either explicitly or parenthetically. Please include a definition. 3. In INT-11, be able to transmit "electronically" is unacceptable. Does this mean by email? This is electronic. If it means to use e-tag, please clearly state it as electronically is not good enough.
Individual
Leland McMillan
NorthWestern Energy
Agree
Agree
NorthWestern is concerned that BAs would have to accept the role of the IA. A Balancing Authority should not be held responsible for timing that is at the mercy of the software provider, Internet traffic, etc.
Agree
Disagree
NorthWestern is concerned that entities would have to accept the role of the IA. These entities should not be held responsible for timing that is at the mercy of the software provider, Internet traffic, etc.
Disagree
No registered entity should be held responsible for any incident outside its control.
Agree
Agree
Disagree
R1. R1 requires that the Sink Balancing Authority distribute each Arranged Interchange to the various entities specified in the Requirement “less than one minute after receipt of any Request for Interchange…” NorthWestern is very concerned by this requirement and strongly believes that a Balancing Authority should not be held responsible for timing that is at the mercy of the software provider, Internet traffic, etc. The time to act on a Request for Interchange can and must be managed by the Balancing Authority personnel, but placing the distribution time requirement on the Balancing Authority is unfair and misdirected. R4. It is unclear what “associated with a direct-current tie operator” means in the context of the Requirement. Does this mean that a Balancing Authority that is a direct-current tie operator must follow the requirement, or any Balancing Authority that receives a Request for Interchange that includes a direct-current tie operator as a party to the Request for Interchange? R7. The concern described for R1 also applies to the one minute notification timing requirement included within R7.
Agree
Agree

NorthWestern agrees, but has a separate issue with R4. It is unclear what "associated with a direct-current tie operator" means in the context of the Requirement. Does this mean that a Balancing Authority that is a direct-current tie operator must follow the requirement, or any Balancing Authority that receives a Request for Interchange that includes a direct-current tie operator as a party to the Request for Interchange?
Agree
Agree
Agree
Agree
Disagree
NorthWestern is not aware of any further requirements necessary for reliability.
Disagree
NorthWestern is not aware of any such conflicts.
NorthWestern appreciates this opportunity participate in the commenting process.
Group
Platte River Power Authority
Deb Schaneman
Agree
Agree
Agree
Disagree
Key tasks for Interchange Coordination has a reliability function, however, without defined Measures (TBD) it is difficult to determine how a registered entity will prove compliance during an audit other than demonstrating the use of an electronic tagging system. It seems inherently impossible to meet other INT Standards without the capability to meet the key tasks for Interchange Coordination. Therefore, we don't feel that these tasks must be specified in a standard as a requirement.
Disagree
If tools are unavailable due to a cyber attack or other incident, an entity such as the Reliability Coordinator should declare an emergency and have the authority to suspend interchange coordination or implement a procedure for manual interchange coordination. It should not be left to the Compliance Monitor's discretion on a case by case basis to determine whether or not a violation of this requirement occurred.
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Disagree
Disagree

Disagree
Group
Entergy
Melinda Montgomery
Agree
Agree
Agree
Disagree
Having the capability to coordinate interchange more properly belongs in certification, so this standard should be eliminated.
Disagree
Entergy believes that this type of language is necessary to ensure compliance is not strictly enforced in situations where non-compliance is unintentional. However, we do not think that NERC's enforcement of these standards will be influenced by footnotes, so we would propose that this language is more directly incorporated into the INT standards where appropriate.
Agree
Agree
Disagree
Entergy believes Requirements R1 and R7 as written are overly complex. Also, this standard seems to complicate interchange coordination without improving reliability.
Disagree
Entergy agrees with the requirement tied to Balancing Authorities (R2.1). Entergy does not agree with the requirement for Transmission Service Providers (R3.1) to deny based on projected system conditions as TSPs. The role of the TSP is to model available transmission capability, while the role of the Transmission Operators is to perform security assessments of the operating timeframe. TOPs currently do not have a role in interchange assessment, so we believe that the requirement should be removed.
Disagree
Entergy believes that curtailments are real-time reliability actions, and denials impair the reliability of the BES. Therefore, the language "if (the BA) can support the magnitude of the Interchange" decreases the effectiveness of curtailments for resolving reliability problems. Instead of the Balancing Authority which requires relief receiving it, the other BA(s) associated with the curtailed transaction may deny based on the burden to their system(s). The requirement language also implies that the BA denying such a curtailment may be failing their reserve requirements since they are unable to allow the curtailment request.
Agree
These criteria are correct, but Entergy would recommend adding an "if applicable" statement to the two requirements that list "the direct-current tie Operating Balancing Authority" since not all Reliability Adjustments include a DC tie.
Disagree
How are the RCs and TOPs supposed to be able to know in advance of the real time flows exactly how many MWs of curtailment would be required in the case of a projected SOL or IROL exceedance? Since interchange schedules can be submitted until a few minutes before ramp start, then the day-ahead assessments have limited impact on maintaining real-time reliability conditions.
Agree
Disagree
The standards should not specify the "how" of interchange checkout between BAs. Forcing adjacent BAs to perform hourly checkouts seems burdensome if Confirmed Interchange Schedules do not change between hours. Entergy recommends changing this requirement to remove the "No more than one hour prior to each operating hour" language in order to allow flexibility in checkout practices.
Disagree

Agree
In questions 9 and 12, the SDT appears to essentially require a preemptive TLR anywhere from hours to a day in advance of the materialization of real time flows in excess of the real time capability of the transmission grid. The preemptive curtailments should occur more closely to real-time so that the assessment is more meaningful to real-time system conditions.
Individual
Marcus Lotto
Southern California Edison Co.
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Disagree
Disagree
Agree
Group
NERC Staff
Gerry Adamski
Agree
Agree
Agree
Disagree
INT-011 does not appear to serve any specific reliability purpose, and seems primarily to be focused on requiring the use of software tools and procedures. While we believe there is value in the industry agreeing on a common set of tools and practices related to Interchange coordination, we question if they should be required in a reliability standard and monitored for compliance.

Agree

Agree

Agree

Disagree

The level of detail in these requirements seems intended to codify the behavior of software tools currently in use. While we believe there is value in the industry agreeing on a common set of tools and practices related to Interchange coordination, we question if they should be required in a reliability standard and monitored for compliance.

Agree

Agree

Agree

Agree

Agree

Disagree

Disagree

Disagree

NERC believes the draft requirements are very well written, and offers its compliments to the CISDT. There are several terms used in the standards that do not appear to be defined in the NERC Glossary: "On-time Arranged Interchange," "Reliability Adjustment," “SOL,” “Transmission Facilities,” “Entity Registry,” and “Load Balancing Authority.” NERC suggests the CISDT either define these terms or consider alternate wording in the standard. In general, NERC asks the members of the CISDT and the industry at large if there is truly a need to have the all the details specified in the draft standards as mandatory and enforceable requirements. While we believe there is value in the industry agreeing on a common set of tools and practices related to Interchange coordination, we question if those tools and practices should be required in a reliability standard and monitored for compliance.

Individual

Ron Gunderson

Nebraska Public Power District

Agree

Agree

Agree

Disagree

The standard should outline the funtional requirements (redudancy in communications, servers, etc.) for the design of the tool. If the tool is meets design requirements, there should not be a standard violation if there are elements outside of the entities control that hamper the ability to respond to respond in the event of failure of the internet. Leaving the decision to the discretion of the auditor is ambiguous and inconsistent and places all risk on the entity involved on issues beyond the entity's control. This is not acceptable.

Agree

Although I agree the requirement can be retired, there is some question about the statement metered values for Dynamic Schedules. Not all Dynamic Schedules are metered (with traditional metering equipment). There needs to be a mechanism to document the final hourly interchange, but it is not necessarily a meter for Dynamic Schedules

Agree

Agree
Although we agree with the philosophy of the SDT to limit the one minute requirement for distributing Interchange information to only those cases that impact reliability, the requirements are anything but straightforward. Without the explanation at the beginning of the question, it would be very difficult to determine the intent. There should be a simpler way to implement the intent of the SDT.
Disagree
Although the reasons should be specified, we do not agree that the Source and Sink Balancing Authority needs to know proper connectivity throughout the entire path. Intermediate Balancing Authorities should verify connectivity to adjacent Balancing Authorities. It is unrealistic for the Source or Sink Balancing Authority to know the connectivity of all the Balancing Authorities in North America.
Disagree
Reliability Adjustment Requests should be approved period. To deny for lack of ramp will degrade the reliabiltiy of the interconnected system. For example, if an IROL is violated due to a sudden change in flow due to a contingency and a BA can deny the curtailment because it can't ramp in the change quick enough means there will be no relief when in fact there could be some relief if the change was ramped in as quickly as it could be. Another example is a DC tie trip between interconnections. The BA on the inverter side will experience a sudden and immediate loss of injection that probably will not be to serve load on its system and be expected to make up that loss just because another entity doesn't have enough ramp to meet the curtailment. This proposal doesn't make any sense from a reliability perspective. Curtailments for reliability reasons MUST be approved.
Disagree
Requirements 5.2 and 5.1 must include the BA on both sides of a DC line that crosses between interconnections. For a DC tie that crosses an interconnection, the Balancing Authorities on both sides of the DC Tie are effectively source/sink for the transaction in that interconnection and for that reason alone need to approve or deny the transaction.
Disagree
The standard should apply to RC's since they have the wide area view. The transmission operator should not be responsible for montioring IROLs as the RC should have the big picture for them.
Agree
Agree assuming that a DC tie is considered a Transmission Facility.
Disagree
Disagree
As noted above there are areas that are not clear and consise and at times are confusing. Also the notes to allow exceptions to timing requirements based on auditors discretion will not result in even treatment at times when extreme circumstances exist.
Disagree
Measures are missing for most standards. They need to be developed or the requirements removed. There should not be a requirement that cannot be measured.
Group
PJM
Patrick Brown
Disagree
The phased in approach is neither good nor bad. PJM however would suggest a simplified approach: – Stick to the basics for writing reliability requirements related to coordinating Interchange – i.e. RFI approval is required before implementation (no approval, no implementation) – make a clear distinction between tools (e-Tag) and entities – treat all RFIs the same no matter HOW they get implemented (i.e. dynamic schedules should be treated in the same way as normal schedules with regards to confirmation – and leave the Business rules to NAESB and the Markets) Regarding Dynamic Transfers, NERC needs to make clear that Dynamic Transfers are simply a means of implementing a Confirmed Interchange. A pseudo-tie is identical to a dynamic schedule and is not a means to avoid reserving transmission for a given point-to-point transaction.
Disagree
PJM does not agree that the IA should be removed from the standards. It should be noted that none of the NERC and FERC approval functional entities are “actual entities” until a corporate entity registers (or is registered) by NERC to comply with the standards written to the respective

functions. The FM and the FMWG has consistently stated that the default position is that if no entity registers as an IA, then the Regional Entity must register someone and it is reasonable that the sink BA will be held responsible for the IA requirements. The SDT must address the issue that a software checkout tool is a means of checkout and is not the functional entity itself. PJM does agree that the failure of an INTERCONNECTION-WIDE tool should not be considered as non-compliance for the respective sink BA. The SDT should continue to seek consensus on rewording the standard such that BA compliance is based on the information provided to it (i.e. if the tool incorrectly provides confirmation on an Arranged Interchange (AI), and the BA acts in good faith on that information, then the requirement should recognize that the BA is compliant when it Implements that AI.) That does not mean that no one is responsible for checkout. A BA should never be excused from only implementing AIs that it knows or is informed has been confirmed. If there is no such knowledge or third-party confirmation, then there can not be any implementation of such not confirmed schedules.
Disagree
There is no need for the proposed new term. The SDT introduces a new term (Interchange Coordination) and uses the term in the title but the term is not used anywhere in the requirements. What the term also does is to further confuse the concept of a Task for coordination with the Tool used for coordination.
Disagree
Here again, the SDT presumes the need to remove the IA. That question should be asked before proceeding with requirements to replace the task. The tasks listed in INT-011 are business practices not reliability issues. INT-011 is written as a certification requirement. R2 (the main requirement) states that the BA must have the “capability” to do the following. Thus the sub-requirements refer back to capability, they are themselves NOT requirements that must be complied to
Disagree
No, the phrase does not help. The phrase "where Interchange Coordination is non-functional" seems to really mean "when the Interconnection wide tool isn't operating". If the tool isn't working then the sink BAs must do that checkout without the tool. But the checkout must be done, otherwise all RFI will / must be rejected because there will be no validation that everyone has agree to the proposed RFIs. Compliance monitors are not reliability entities. They are more likely to get around to investigating an event at the end of a month then they are to helping a real time concern. The footnote does not add anything to the standard. Compliance Monitors have always had discretionary options. Transaction information must be agreed to "in all cases". Without agreement BAs will be at risk of raising generation while another BA is dropping load. The only reasonable alternative is only to make changes that have been confirmed (with or without OATI)
Agree
The currently approved INT-001, as written, establishes responsibilities. PJM agrees that the elimination of this standard will not cause a problem for the simple reason that every other requirement establishes a responsible entity for the given task defined in the respective requirement. If done correctly the SDT only needs a requirement that Confirmed Interchange be transitioned to Implemented Interchange. There is no need to carve a special condition for Dynamic Schedules. If the Dynamic Schedule represents a point-to-point transaction it still requires that all parties agree with the terms of the transaction.
Agree
Disagree
PJM is satisfied that the reliability conditions are established and ensured by INT-003-2. The current and the proposed INT-006 impose subjective, unmeasureable procedureal mandates (e.g. the BA shall evaluate a schedule with respect to….) There are no measures associated with the current standard. PJM could support deleteing INT-006. The proposed INT-006 does correct the subjectivity of the old INT-006, but does so at the expense of imposing administrative guidelines that could, under emergency conditions, divert a system operator attention to focusing on RFI at the expense of evaluating system conditions.
Disagree
The reliability issue is whether or not the Interchange is approved or denied. The reasoning for that decision is not a reliability issue as much as it is a business issue. The idea of listing the reasons for denial merely limits the BAs reliability options for denying a business request. Being too busy to evaluate a request is a legitmate reason for denying a request that may or may not be harmful to the system (i.e. the BA does not want to operate in an unexamined system state.)
Disagree
A NERC requirement should not impose an ad hoc approval or denial. Each request must be evaluated in the context of the system conditions at the time.
Disagree

As in the response to Question 8, the reliability issue is the approval/denial of the Interchange. The rationale for approval/denial is a business issue. There is no reliability reason for imposing "passive approval" of AIs. "Passive denials" would be more reliable because it only accepts actively approved AIs thereby avoiding operations in an unexamined system state.
Disagree
R8 is redundant with TOP-005-2 R2 R9 is redundant with IRO-001-1.1 R9 (all issues) & IRO-009-1 R3 (Day Ahead IROLs)& IRO-004-2 R1 (the BA must follow directives).
Disagree
This is a Business issue not a reliability issue.
Disagree
The proposed requirement does not meet the FERC directive for clarity. The requirement must be clear regarding who is responsible for compliance. As written it is not clear which BA would be held non-compliant for a disagreement. The proposed requirement requires the BAs to ensure the validity of the data. The BAs need only decide on whether or not they can implement the Arranged Interchange based on the data. If the data is invalid the BAs must reject the request. As noted in the response to Q1, a better approach is to maintain a single requirement that if there is no agreement then there is no implementation.
Disagree
See response to Question 17.
PJM would suggest the SDT directly address the issues that they the SDT propose to remedy: 1. Define the data that must be coordinated for reliability • Magnitude • Start and end times • Rate of change • Source/sink 2. Distinguish between coordination tools and reliability entities. For example: Require that BAs only implement CONFIRMED INTERCHANGE; then as sub-requirements list the acceptable means of doing that: • By using an Interconnection-wide tool that the BAs will use as the basis for demonstrating that they met the coordination requirement for each CI; or • By BA-to-adjacent BA checkout where using the same inter-area net values as confirmation that they met the coordination requirement 3. Seek NERC approval to make the data in the interconnection wide tool available to the RC for review. PJM does not agree that the RC should be included in the interchange coordination process because the TOP and RC currently (IRO-001-1 R3 to R9) has the authority to reject any schedule at any time that it deems the system is or will at risk (IRO-004-2 R1) Let NAESB define and maintain the timing requirements and the boundaries for what can and cannot be used for Dynamic Schedules. [As long as both BAs agree to the magnitude of a schedule, the system will be in balance.]
Group
Bonneville Power Administration
Denise Koehn
Disagree
Dynamic Transfers should be addressed in a single standard. All dynamic transfers have an impact on the grid and should be treated equally and simultaneously in standards development. Addressing dynamic schedules while leaving pseudo ties out of the requirements leaves a huge hole in the standard. Standards dynamic schedules and pseudo ties should be developed in a single phase. Please advise the CI SDT to be cognizant of the downstream effects that multiple Standard revisions create. Each time a new Standard version is issued, staff responsible for demonstrating compliance is required to provide documentation covering each period of time within the calendar year that each version is in effect. Multiple Standard versions within a calendar year create a lot of documentation efforts. Please limit versions to the minimum number possible.
Agree
Agree
Agree
Agree
Agree
Agree
Agree
We agree with the approach. However, how does the Sink Balancing Authority demonstrate compliance with the less than one minute distribution requirement? Will each tagging software

vendor provide a check that records or logs the demonstration of each distribution's meeting the 1-minute-or-less threshold? We believe the data is logged today. We're not certain that a check is made to ensure distribution occurs within a minute or less timeframe as well as documented evidence of such.
Disagree
We are struggling with how a Transmission Service Provider proves that it denied Arranged Interchange whenever its transmission system did not have the capability to accommodate Arranged Interchange based on "projected system conditions". The latter term is vague and seems difficult to validate that whenever such conditions occurred, the TSP responded with denial actions.
Agree
Agree
Agree
Agree
Disagree
Disagree
Disagree
Some of the revised Standards (e.g., INT-006-4) tend to have wordy requirements that make them not only difficult to interpret but also make demonstration of compliance more complex. Shorter, very specific language is preferred.
Group
FirstEnergy
Sam Ciccone
Agree
We agree with the two phase approach. However, we ask for clarification: Does this mean the SDT will ballot the first phase standards and obtain FERC approval while working on phase two?
Agree
Disagree
The definition of Interchange Coordination in the standards should be consistent with, build on, and support the definition of Interchange Coordinator in the Functional Model Version 5. Consequently, we suggest the following adjustment to the definition of Interchange Coordination – "The act of using commonly available tools to ensure the communication of Arranged Interchange for reliability evaluation purposes and coordination of implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas including full disclosure to all the parties involved."
Disagree
Fundamentally, the approving and denying of Arranged Interchange is the reliability-related task that initiates a transaction's implementation process. Consequently, that approval process and the implementation process are what need to be included in the standard. The rules concerning the submission of a request are business practices that should be determined by NAESB. The only requirement that a PSE should have a method for providing the Request for interchange electronically and that the information they provide related to that request is accurate and complete.
Disagree
It seems the drafting team's statement, "In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred." assigns a compliance auditor an authority that they already have. This statement seems unnecessary. As an alternative the drafting team should require an entity to document and implement a manual process when the electronic capability (tool) is unavailable. Furthermore, in those extreme circumstances, the Standards of Conduct and Market Activity will be suspended and interchange activity will by necessity be managed by the BAs and TOPs.
Agree

Agree
Disagree
The one minute time limit appears to have sprung from the e-tag system specifications document and was related to ensuring market activity was unimpeded (i.e. first request through the door was the first request considered for implementation). The speed with which these transactions are managed is a market issue. The requirement should be to implement the schedule as approved. R1 and R7 may be difficult to measure and prove compliance during times of system failures. In R1.1 and R7.1 it is not clear what constitutes "on time."
Disagree
This requirement appears to limit the "reliability reasons" for denying a transaction to only those listed. We seem again to be mixing business practices with reliability-related issues. In R3.1, the transmission path is contractual and may not accurately represent the actual flow; therefore, this may be a market issue and may not directly be a reliability issue.
Disagree
Reliability Standards should not require the approval of market related transactions. The BA should only be required to deny a transaction if it cannot reliably implement the proposed transaction. The rules and requirements for approving transactions belong in the NAESB WEQ.
Disagree
Reliability Standards should not require the approval of market related transactions. The BA should only be required to deny a transaction if it cannot reliably implement the proposed transaction. The rules and requirements for approving transactions belong in the NAESB WEQ.
Agree
However, R9 is contained in R8. The "or IROL" should be deleted from R8 as it is covered by R9.
Disagree
4.1 and 4.2 are contractual arrangements that do not necessarily equate to a reliability issue. R4.3 may or may not represent a reliability concern. The statement "provided that concern is supported by evidence" in R4.5 is heavy handed. It implies that Mr. BA, TSP, or RC may cut the transaction, but you better make sure you have evidence to support that decision. By requiring these entities to adjust the transaction for "Any real-time reliability concern related to a specific Confirmed Transaction" you directly require evidence to prove compliance with the requirement. This makes the phrase "provided that concern is supported by evidence" in R4.5 redundant and unnecessary. It should be deleted.
Agree
NOTE: We clicked "Agree" in the on-line comment form to signify that we agree with the SDT's choice to not specify a method to reach agreement when conflicts arise. However, it is not unreasonable that a business rule be written that requires resolution of conflicts procedure. It is also reasonable to allow reliability entities to not implement a transaction that has not been agreed to by everyone prior to implementation.
Agree
NOTE: We clicked "Agree" in the on-line comment form to signify that we do not think there are any requirements missing. However, it appears throughout the standards development that the drafting team is mixing business practices with reliability-related issues. A review by the team of the proposed standards to ensure that business practices are managed by NAESB and reliability issues are housed in the NERC Standards is appropriate and necessary.
Agree
NOTE: We clicked "Agree" in the on-line comment form to signify that we are not aware of any conflicts between the proposed standards and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement.
FE has the following additional comments: 1. It seems the drafting team's statement, "In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred." assigns a compliance auditor an authority that they already have. This statement seems unnecessary. The requirement should allow the reliability entity to suspend market operations and Standards of Conduct when extreme situations such as where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes. The circumstances cited truly represent a threat to reliability on an emergency level that 888 and 889 envisioned with the inclusion of a provision to suspend market operations during an emergency. 2. INT-004-3 – (a) Applicability and Req. R2.3 – Although the standard applicability section and Req. R2.3 lists the Transmission Operator (TOP), the TOP does not appear to have any responsibilities. Main Req. R2 is only applicable to the Purchasing-selling Entity. We suggest that the SDT remove the TOP from the applicability section A.4. (b) In Req. R1, the phrase "Load-serving, Purchasing-Selling Entity...", we feel that the phrase is awkwardly written and may be misinterpreted to place responsibility on the

functional entity "Load-Serving Entity". We suggest rewording R1 as follows: "The Purchasing-Selling Entity that provides Load associated with a Dynamic Schedule shall ensure...". 3. Effective Date – We feel that the proposed effective date of the "first day of the first calendar quarter following the date this standard is approved by regulatory authorities..." does not provide the entities appropriate time to implement these extensive changes. From a compliance evidence standpoint, the changes will create much additional work due to all the revised, transferred, and retired requirements. Also, INT-011-1 is a new standard and there may be responsible entities that will need adequate time to provide the required support for interchange coordination. We suggest the SDT consider increasing the implementation period by at least two calendar quarters. 4. We noticed that the VRF and Time Horizons are not shown in the draft requirements. Is the SDT planning to develop these in a later draft?
Group
GSOC & GTC Response
Guy Andrews
Agree
Agree
Agree
Disagree
The requirements as listed in the standard are not to perform the tasks, but to be capable of performing them. This standard reads more like a list of requirements for certification rather than a measure of compliance. It’s misplaced as a standard.
Disagree
We understand the intent here but believe that the footnote language should be moved into the requirements to make them part of the standard. Requirements and measurements should not be listed in footnotes.
Agree
Agree
Disagree
Remove these requirements completely.
Disagree
Postings and associated reservations made on OASIS are based on studies. The TLR process is defined for curtailments.
Agree
Agree
Disagree
It seems out of scope for a TOP to manage or predict next day real time flows in order to accurately curtail transactions.
Agree
Disagree
Requirements should specify what must be accomplished – not tell how an entity should accomplish it. Procedures should be left up to the entities.
Disagree
Disagree
Group
Midwest ISO Stakeholder Standards Collaborators
Jason L. Marshall
Agree
Agree

Agree
Agree
Agree
Agree
Agree
Reloading of transactions does not support reliability but rather supports continuance of commercial activity once the reliability event is over. Thus, reloading of transactions does not belong in reliability standards. It would be an issue better dealt with by NAESB.
Agree
Agree
Language should be added to define that the only responsibility to validate adjacency of a scheduling path (in 2.1) to a BAs own interconnection. Similarly, each TSP (in 3.1) will only be responsible to validate adjacency of a transmission path only to the extent of its interconnecting TSPs.
Disagree
Language should be changed to On-Time Reliability Adjustment Requests. "Late" (and even past-) requests MAY still be approved, but should not be a NERC defined "Must". E-Tag specifications may be changed to passively-APPROVE reliability adjustment requests to accommodate this standard, but that should only be automatic if the request is On-Time.
Disagree
Language is needed to more accurately define direct-current tie Operating Balancing Authority, and its communication role, as that role may not be otherwise designated in the e-Tag's approval path. As well, a DC portion of the transmission path may not be designated on an e-Tag, and may be completely unknown to the Sink Balancing Authority.
Disagree
These requirements are not needed and will only duplicate existing requirements that adequately address the need to assess interchange transactions on a day-ahead basis. IRO-004-1 R1 already requires Reliability Coordinators to perform next day studies for “anticipated” conditions “to identify potential interface and other SOL and IROL violations. Day ahead energy schedules would clearly fall into anticipated conditions. IRO-004-1 R2 requires each Reliability Coordinator to “pay particular attention to parallel flows”. Again day ahead energy schedules fall into this parallel flows. IRO-004-1 R3 requires each Reliability Coordinator to develop action plans that may be required to alleviate IROL and SOL violations. One option for the action plans explicitly states curtailment of Interchange Transactions as an option. IRO-004-1 R6 requires the Reliability Coordinator to direct action to alleviation these IROL and SOL violations identified in the next day studies and IRO-004-1 R7 requires the Transmission Operator, Balancing Authority and Transmission Service Provider to comply with the directives based on the results of these next day studies. TOP-002-2 R5 requires Transmission Operators to plan to meet “scheduled system configuration, generation dispatch, interchange scheduling and demand patterns”. TOP-002-2 R11 requires the Transmission Operator to perform a next day study. Thus, a Transmission Operator would have to include day-ahead interchange schedules in its next day study in order to plan to meet them. Then TOP-002-2 R10 requires the Transmission Operator to plan to operate within IROLs and SOLs.
Agree
Disagree
Midwest ISO "agrees" to the intent of the requirement and that no default procedure is necessary. The requirement language should remove the words "No more than one hour". Scheduled interchange may be agreed to prior to that OH-1 along with other hours of static MW flow, for example. If this previously agreed-upon interchange schedule has not changed, no further communication should be needed.
Disagree
Disagree
Individual

James H. Sorrels, Jr.
American Electric Power (AEP)
Disagree
Disagree
Currently, there are applicable entities in the NERC functional model which are registered as IAs. We believe that the current process is not broken and that the IA just needs to be better defined. Note: Please refer to question 17 for additional comments on the rewrite of the Standards.
Disagree
Disagree
The different RTO and Market models across the BES compromise the intent of the Standard and Requirements. As a result, they are not properly represented with what actually takes place in the Interchange Scheduling process. Also, they do not address the current involvement of PSE or CPSE relationship to the BAs. Note: Please refer to question 17 for additional comments on the rewrite of the Standards.
Agree
Agree
We agree that it is unimportant who creates the Arranged Interchange. Confirmation by all affected applicable and reliability entities are what are ultimately important.
Disagree
This should pertain to all impacted Interchange Schedules, where the releasing entity should electronically notify release of reliability profile curtailment. Verbally, as a backup, if the electronic process has failed to ensure Sink BA ultimately as needed.
Disagree
We do not agree that Sink BA should be responsible to distribute. This should be a function of IA or NERC.
Disagree
Different Market models and structure, such as SPP, do not line up with the intent of what this Standard is trying to accomplish. While we agree with intent, concept and approach, they are not reflective of the different Market models currently in operation today.
Agree
When it involves a reliability request, all applicable entities should try to accommodate to the best of their ability. Magnitude and ramp may actually be a less significant factor than unloading a transmission line or shedding load based on the situation.
Agree
Active approval and reliability assessment should always occur.
Agree
Agree
Agree
The present SPP structure and EIS Market needs to be addressed, while still having individual BAs needs addressed to meet the intent of this Standard.
Agree
Please refer to question 17 for additional comments on the rewrite of the Standards.
Agree
Yes, different Market models and structure, such as SPP.
INT-004-3 Rewrite Comments: The purpose statement should also include pseudo tie interchange besides the dynamic schedule reference. While BAL-005-0.1b deals the metering aspect, it does not address that in many cases the pseudo tie interchange is not being accounted for appropriately in the NERC IDC. This was a very apparent finding from the Northeast Blackout of 2003. The unscheduled flows and reliability impact of pseudo ties still remains a problem today. Regardless of where the BA has the pseudo tie is contractually modeled to, the affecting source or sink impact on reliability still comes from the response factor of actual physical location. R1: If the Load-serving PSE is only responsible for ensuring the RFI is submitted to the Sink BA, who is responsible for making sure the Source BA has the same confirmed schedule intent to ensure generator to load balance? This could imply the Source BA does not need to know, while it is presently a function of the Interchange Authority and its electronic process. R2 and its sub-requirements: The BES does not operate to average energy profile values. It

operates to real-time values and changes. Average energy profile is a Market accounting and settlement term, which has no place in real-time operation or its tools/process, such as IDC or interchange scheduling, for managing congestion or reliability impact. R2.3: The average energy profile term is used in the preceding requirements, yet the hourly energy profile term is used in R2.3. All reliability impact is based on the actual operating value at a specific time, regardless of what is on the forecasted dynamic schedule value. These actual operating values are not continually identified in the IDC, which accounts for the unscheduled flow issue. This is why it is extremely important to continually have the forecast dynamic schedule match the impact of the actual operating value. Actual operating values can different greatly from forecasted dynamic average energy profile, enabling the root cause to not be identified in IDC and forcing other interchange to be curtailed instead. The intent of Standard INT-004-3 is to address a needed reliability process. However, it does not cover the impact of unscheduled flows caused by pseudo tie interchange. The requirement parameters for deviation are reactive in addressing the actual operating impact, just as the IDC curtailment process is sometimes reactive. Since the maximum actual energy cannot exceed the transmission reservation that has already been reliably assessed in the OASIS reservation/priority process, we recommend the PSE continually matching forecasted dynamic schedule to actual operating value and communicate to the IDC. It might be impossible to do this on forecasted dynamic schedule interchange that frequently changes with significant magnitude. The only way to realistically accomplish identification and communication of reliability impact to the IDC would be to somehow send these actual interchange values. INT-006-4 Rewrite Comments: R1 Proposing that the Sink Balancing Authority shall be exclusively responsible for distributing Arranged Interchange is totally contradictory to the Interchange Scheduling process and purpose of the Interchange Authority in the present NERC functional model. It appears to put all the burden of arranging and distributing AI to the Source BA. This concept appears to be going back to the days of and former model of Control Area and bundled utility, in which adjacent CA’s confirmed interchange schedules. In today’s model, open access Market and all of the granular applicable involved entities in the NERC functional model and process, it does not seem realistic for the Sink BA to be responsible for distribution in an electronic E-Tag process environment. Many NERC approved Regional Transmissions Organizations (RTOs) have different models and interchange scheduling tools, processes and congestion management mechanisms. They are also registered as the Interchange Authority in the NERC functional model. There is nothing wrong with the current electronic scheduling process (E-Tag and Vendor Tagging Authority). NERC and the Industry would be better served to clearly define what the applicable IA entity really is and means. Possibly, NERC should be the IA responsible for the electronic process and backup for distributing the necessary interchange scheduling and reliability information to the applicable entities defined in its functional. It makes sense for the current RTOs, such as PJM, SPP, etc., to be registered as the IA for their areas. It should be up to them how this interchange information is distributed within the intent of the NERC Reliability Standard through their choice of vendor, electronic tagging authority specifications and contract to meet the Requirements. The second option should be NERC itself. How can a Sink BA be responsible in an open access/Market environment with all of the multiple entities involved? The Sink BA does not actually make the Request for Interchange (RFI) or arrange the interchange. The affiliated PSE or designated CPSE does through its Tagging Authority service and the NERC Interchange Authority E-Tag process. R2.1: There are many aspects that can compromise a Source or Sink BA’s ability to determine the meeting of the magnitude of Interchange and ramp. With the different RTO and ISO models, especially with respect to Market protocols and impacting granular entities, such as Independent Generator Operators, how can a BA solely determine capability of supporting ramp? For example: In the Southwest Power Pool/RTO and Energy Imbalance Schedule Market model SPP is the tariff administrator, transmission service provider, scheduling control area (SCA - according to the OATI IA tool) and it deploys Market Participant GOPs. Yet it has individual membership BAs responsible for demonstrating the ability to meet ramp and magnitude of Interchange to meet performance standards involving generation to load balance, while the Market is deploying GOP resources that could contradict this effort. Applicability: Agree with adding the 4.3 Reliability Coordinator and 4.4 Transmission Operator entities. INT-009-2 Rewrite Comments: In the case of Markets, such as SPP, where there are continual market interval Interchange changes of significance impact on ACE and deployments to independent GOPs that do not follow the intent of meeting generation to load balnce, who is responsible for confirming before implementation into the member BAs’ ACE equations? Also, see comments above in R2.1. These types of Market models compromise the intent of meeting the generation to load concept meant to be addressed in the Balancing and Interchange Standards. Retirement of Standards Comments: The current IA process and concept should remain but needs to be better defined. If not, NERC should administer the IA process and electronic Interchange distribution of RFI and AI to the affected/applicable reliability entities for assessment and approval.

Individual
Greg Rowland
Duke Energy
Agree

Agree
We agree with removing the IA. However does elimination of the IA place more compliance responsibility on the Sinking BA? And is the Sinking BA the appropriate entity? As opposed to the Purchasing Selling Entity, for example?
Agree
Disagree
We agree that the lists of tasks are appropriate and sufficient to arrange interchange. However requirements to have "capabilities" should be certification requirements and do not belong in a Reliability Standard. This standard should be eliminated.
Agree
Agree
Agree
Agree
Agree
We agree, but believe that the language could be more clear that you are only responsible for validating paths relevant (i.e. adjacent) to your system.
Disagree
Language should be clarified such that only On-Time requests should be REQUIRED to be approved.
Agree
Disagree
We believe that these requirements are more appropriately addressed in the IRO standards, rather than in the INT standards.
Agree
Disagree
Disagree
Agree
In questions 9 and 12, the SDT appears to essentially require a preemptive TLR anywhere from hours to a day in advance of the materialization of real time flows in excess of the real time capability of the transmission grid. This would inappropriately reduce the liquidity and optionality afforded by the current physical rights of tariffs for transmission service.
• Given that the BA has been given additional responsibilities, where and how are the specifications for INT transactions defined? The drafting team needs to address this issue. • INT-009-2 Requirement R1 – for this requirement, you should not have to re-confirm schedules that have not changed from previous hours.
Group
PacifiCorp
Sandra Shaffer
Agree
Agree
Agree
Agree
Agree
Agree

Agree
Agree
Agree
Disagree
In cases of reliability adjustments (curtailments), PacifiCorp does not believe that there are any valid reasons for denying a curtailment.
Agree
Disagree
Agree
Disagree
The words “no more than one hour prior to each operating hour” are ambiguous and could potentially be interpreted to preclude a preschedule check-out. To clarify, PacifiCorp suggests that the language read “at least one hour prior to each operating hour….” or, in the alternative, the words “no more than one hour prior to each operating hour” should be eliminated entirely.
None at this time
None at this time
None at this time
Individual
Kathleen Goodman
ISO New Enlgand Inc.
Agree
Agree
We agree that assigning the standard requirements, as suggested, to the Sink BA does not conflict with the functional model. Since there may be more than one Interchange Coordinator, the assignment of these requirements to the Sink BA provides clear guidance to the industry on the entities that are responsible for these functions and does not raise additional questions of interpretation that the assignment to the IC could create.
Disagree
We do not agree that this defined term is necessary; the desired concept can be described in the purpose without creating a new definition.
Disagree
We agree with the concept of including the required tasks in the standards; and with the current layout of the other standards putting them all within INT-011 is a reasonable approach. However, the phrase “that desires to” is not measureable and should be removed.
Disagree
We agree that no one should be found non-compliant if the hardware/software is not available to support these tasks, but we are not sure that these footnotes are the best way to achieve that goal. Can statements be made in the measures and compliance to address this rather than a footnote?
Disagree
The SDT seems to have missed the distinction made in the original set of standards. INT-001 establishes the mandate that special case interchange be explicitly assigned to some entity. In the case of Inadvertent Interchange payback, such payback can be initiated by either BA that has an accumulation, but R2.2 clearly mandates that the responsibility falls on the sink BA. The SDT would be better served to raise the issue of whether or not Inadvertent Interchange is a reliability issue or a business issue. Where INT-001 relates to a single Interchange, INT-009 relates the sum of all Confirmed Interchange and to the fact that the net of Conformed Interchange only goes into the ACE equation. These are two distinct functions. INT-009 recognizes that NET Interchange is done among adjacent BAs. INT-001 assigns responsibility to BAs that may or may not be adjacent.
Agree
Disagree

While we agree with the general approach of INT-006, we have the following comments/questions. With respect to the specific requirements of R1, we agree with R1.1, but we do not understand how R1.2, R1.3 and R1.4 apply to the general statement in R1 that is talking about distributing 'a request' within a minute of its receipt. For example, if the request has not yet been distributed – how can it have been denied (R1.4). We do not agree with R7.2, 7.3, 7.4. The general text of R7 is to requiring notification of 'whether or not AI was transitioned to Confirmed. The language of R7.2 implies something has already been distributed, yet the purpose of R7 is the actual distribution. If 7.3 or 7.4 are true the notification should be that is WAS NOT transitioned to Confirmed. If the intent is to only require notification of AI that was Confirmed, then the language of R7 needs to be modified to reflect that intent.
Agree
We agree that the list of reasons for denial should be provided in the standard and are appropriate. However, with respect to economic markets, we believe the timing of the reviews should be reconsidered; or an exemption may be required for these timelines in areas with economic markets. For example, in economic markets with submittal deadlines, the system conditions for evaluation of the Arranged Interchange is not understood until those submittal deadlines have passed. Therefore, no action can be taken to 'deny' a request in the timeframes noted. For example, if a new interchange request, Request A, would result in the flow on an interface to exceed the transfer capability – another interchange request, Request B, may be submitted that would net against Request A. There is no reliability issue that needs to be addressed until the market deadline has passed.
Agree
Disagree
The phrase 'shall not transition an Arranged Interchange to Confirmed Interchange' appropriately utilizes the currently defined terms, but it is not clear what action should be taken. Should there be a transition to a state of denied?
Disagree
We do not believe these new requirements are appropriate for the following reasons: (1) "Potentially required" is not measurable (2) R8 is redundant with TOP-005-2 R2; and (3) R9 is redundant with IRO-001-1.1 R9 (all issues) & IRO-009-1 R3 (Day Ahead IROLs)& IRO-004-2 R1 (the BA must follow directives). (4) In existing economic markets, where submittal deadlines allow new interchange requests to occur up to 'near realtime', an estimate of the net interchange would be available for coordination on a day-ahead basis but there is no expectation of taking action to modify specific interchange requests on a day-ahead basis as the requirements indicate.
Disagree
(1) The requirement assumes that it defines the complete set of exemptions. However, the IRO and TOP standards do a better job by mandating that the RC and TOP take actions for IROLs not just during an event but also if an event is anticipated. (2) This requirement is redundant with IRO-009-1 R4 (3) These specific reasons do not allow the BA or TSP to make an adjustment is made because of failed checkout or the economics of a transaction in a market. Where are those adjustments allowed?
Disagree
The word "composite" is confusing. Does it mean the net BA to BA interchange or individual BA to BA interchange? The default when there is a disagreement is that the BAs must check each Interchange Schedule and not just Net Interchange. Should special consideration need to be given in the requirements (or only the measures and compliance) for known and planned hardware/software outages that could impact this process for more than one hour?
Disagree
As provided in Q9, Q12 and Q13 above, there may be special 'interpretation' required to ensure these requirements, as written, do not conflict with some FERC approved markets.
General: There are several places where the Load Balancing Authority is used. Why is this term used instead of Sink Balancing Authority? INT-004: Please describe why an AI created for the based on the maximum MW value of a Dynamic Schedule should never need to be modified. This seems to allow everyone to put in a maximum value and leave unchanged for the duration of the interchange. INT-006: The term IA still exists in the timing tables. The table requires distribution of Late and ATF AIs when the language in the requirements is only applicable to on-time AI. INT-009: The addition of the phrase 'and maintain the generation-to-load balance' does not seem to be consistent with the requirements of standards; there are no requirements related to this action. Suggest removing. INT-010: The purpose of INT-010 indications that some Interchange Schedules should be exempt from compliance with 'other Interchange Standards'. The requirements within INT-010 do not seem to be consistent with this purpose. INT-011: The Reliability Coordinator is in the Applicability section but is not mentioned in the requirements

Group
NERC Standards Review Subcommittee
Carol Gerou
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Disagree
Language should be added to specify that the BA's only responsibility is to validate connectivity of the adjacent scheduled path (in 2.1) to a BAs own interconnection. Similarly, each TSP (in 3.1) will only be responsible to validate connectivity of the adjacent transmission path only to the extent of its interconnecting TSPs.
Disagree
Language should be changed to On-Time Reliability Adjustment Requests. "Late" (and even past) requests MAY still be approved, but should not be a NERC defined "Must". E-Tag specifications may be changed to passively-APPROVE reliability adjustment requests to accommodate this standard, but that should only be automatic if the request is On-Time.
Disagree
Language is needed to more accurately define direct-current tie Operating Balancing Authority, and its communication role, as that role may not be otherwise designated in the e-Tag's approval path. As well, a DC portion of the transmission path may not be designated on an e-Tag, and may be completely unknown to the Sink Balancing Authority.
Disagree
A. These requirements are not needed and will only duplicate existing requirements that adequately address the need to assess interchange transactions on a day-ahead basis. IRO-004-1 R1 already requires Reliability Coordinators to perform next day studies for "anticipated" conditions "to identify potential interface and other SOL and IROL violations. Day ahead energy schedules would clearly fall into anticipated conditions. IRO-004-1 R2 requires each Reliability Coordinator to "pay particular attention to parallel flows". Again day ahead energy schedules fall into this parallel flows. IRO-004-1 R3 requires each Reliability Coordinator to develop action plans that may be required to alleviate IROL and SOL violations. One option for the action plans explicitly states curtailment of Interchange Transactions as an option. IRO-004-1 R6 requires the Reliability Coordinator to direct action to alleviation these IROL and SOL violations identified in the next day studies and IRO-004-1 R7 requires the Transmission Operator, Balancing Authority and Transmission Service Provider to comply with the directives based on the results of these next day studies. B. TOP-002-2 R5 requires Transmission Operators to plan to meet "scheduled system configuration, generation dispatch, interchange scheduling and demand patterns". TOP-002-2 R11 requires the Transmission Operator to perform a next day study. Thus, a Transmission Operator would have to include day-ahead interchange schedules in its next day study in order to plan to meet them. Then TOP-002-2 R10 requires the Transmission Operator to plan to operate within IROLs and SOLs.
Agree
Disagree
The NSRS "agrees" to the intent of the requirement and that no default procedure is necessary. The requirement language should remove the words "No more than one hour". Scheduled interchange may be agreed to prior to that first operating hour along with other hours of static MW flow, for example. If this previously agreed-upon interchange schedule has not changed, no further communication should be needed.
Disagree

Disagree

Individual

Dan Rochester

Independent Electricity System Operator

Agree

Agree

From a practical standpoint, we agree with this change on the basis that this does not conflict with the Functional Model. However, this may create a problem if and when an entity steps forward to register as the IA and perform the IA functions. We suggest the SDT consider reverting back to the existing applicability and assign this to the IA, but specifies that given there are no entities registered as the IA and the default is the sink BA, all BAs are required to perform the IA function and hence need to register as one.

Disagree

We do not agree that this defined term is necessary; the concept can be described in the purpose without creating a new definition. However, if the CI SDT decides to maintain this definition, we suggest the SDT coordinate the development of the Interchange Coordination definition with the Functional Model Working Group, which in its FM Version 5 has developed a definition for Interchange and Interchange Coordinator. Having different definitions for similar terms within the NERC documents tend to create confusions.

Disagree

Standards should be written to drive proper behaviors, not to specify the equipment and staff capabilities. The latter requirements belong to Organization Certification Requirements. Further, the term “desire to” is not needed as it makes the standard not measurable. Suggest removing it from R1 and R3.

Agree

Disagree

The SDT seems to have missed the distinction made in the original set of standards. INT-001 establishes the mandate that special case interchange be explicitly assigned to some entity. In the case of Inadvertent Interchange payback, such payback can be initiated by either BA that has an accumulation, but R2.2 clearly mandates that the responsibility falls on the sink BA. The SDT would be better served to raise the issue of whether or not Inadvertent Interchange is a reliability issue or a business issue. Where INT-001 relates to a single Interchange, INT-009 relates the sum of all Confirmed Interchange and to the fact that the net of Confirmed Interchange only goes into the ACE equation. These are two distinct functions. INT-009 recognizes that NET Interchange is done among adjacent BAs. INT-001 assigns responsibility to BAs that may or may not be adjacent.

Agree

Agree

We agree with the general approach of INT-006. With respect to the specific requirements of R1, we agree with R1.1, but we do not understand how R1.2, R1.3 and R1.4 apply to the general statement in R1 that is talking about distributing ‘a request’ within a minute of its receipt. For example, if the request has not yet been distributed – how can it have been denied (R1.4). We do not agree with R7.2, 7.3, 7.4. The general text of R7 is to require notification of ‘whether or not AI was transitioned to Confirmed. The language of R7.2 implies something has already been distributed, yet the purpose of R7 is the actual distribution. If 7.3 or 7.4 are true the notification should be that it WAS NOT transitioned to Confirmed. If the intent is to only require notification of AI that was confirmed, then the language of R7 needs to be modified to reflect that intent. INT-006 was designed to mandate the distribution of information. One could argue that there is a possibility that an IA would collect approvals/denials and not inform anyone of the results, and hence there is a need to mandate that the data be distributed. If one agrees that the data be distributed, one could argue that there is a need to define the time-frame. The NAESB Tables bound the analysis and response times. The Timing Tables in INT-006-3 create a window of 1 minute between when confirmations are mandated and when they are implemented. Given the fact that it takes some time to change the values going into a BA's ACE equation there is not a lot of time to allocate. The one-minute period is consistent with the Tables.

Agree

The reliability reasons for denying an interchange request should be provided.

Agree

Agree
The phrase ‘shall not transition an Arranged Interchange to Confirmed Interchange’ appropriately utilizes the currently defined terms, but it is not clear what action should be taken – should there be a transition to a state of denied?
Disagree
(1) Potentially required is not measurable (2) R8 is redundant with TOP-005-2 R2; and (3) R9 is redundant with IRO-001-1.1 R9 (all issues) & IRO-009-1 R3 (Day Ahead IROLs)& IRO-004-2 R1 (the BA must follow directives).
Disagree
(1) The requirement assumes that it defines the complete set of exemptions. However, the IRO and TOP standards do a better job by mandating that the RC and TOP take actions for IROLs not just during an event but also if an event is anticipated. (2) This requirement is redundant with IRO-009-1 R4
Disagree
The word "composite" is confusing. Does it mean the net BA to BA interchange or individual BA to BA interchange? The default when there is a disagreement is that the BAs must check each Interchange Schedule and not just Net Interchange.
Disagree
We are not aware of any conflicts.
General: There are several places where the Load Balancing Authority is used. Why is this term used instead of Sink Balancing Authority? INT-004: Please describe why an AI created for the based on the maximum MW value of a Dynamic Schedule should never need to be modified. This seems to allow everyone to put in a maximum value and leave unchanged for the duration of the interchange. INT-006: The term IA still exists in the timing tables. Also, the table requires distribution of Late and ATF AIs when the language in the requirements is only applicable to on-time AI. INT-009: The addition of the phrase ‘and maintain the generation-to-load balance’ does not seem to be consistent with the requirements of standards; there are no requirements related to this action. Suggest removing. INT-010: The purpose of INT-010 indications that some Interchange Schedules should be exempt from compliance with ‘other Interchange Standards’. The requirements within INT-010 do not seem to be consistent with this purpose. INT-011: The Reliability Coordinator is in the Applicability section but is not mentioned in the requirements

Consideration of Comments on Project 2008-12 — Coordinate Interchange

The Coordinate Interchange Standard Drafting Team thanks all commenters who submitted comments on the current drafts of INT-004-3, INT-006-4, INT-009-2, INT-010-2, and INT-011-1. These standards were originally posted for a 30-day public comment period from November 10, 2009 through December 11, 2009. There were 30 sets of comments, including comments from more than 100 different people from over 60 companies representing 9 of the 10 Industry Segments. The Standard Drafting Team considered each comment and developed responses and conforming revisions to the set of standards. The NERC Standards Committee placed the project on hold before the responses to this set of comments could be posted. Once the drafting team resumed work on the standards, the decision was made to post the proposed standards a second time with the intention of vetting them against the Paragraph 81 criteria. The Coordinate Interchange Standard Drafting Team posted drafts of INT-004-3, INT-006-4, INT-009-2, INT-010-2, and INT-011-1 for a 30-day public comment period from July 25 – August 23, 2013. The posting was designed to gather stakeholder feedback regarding the proposed requirements, especially with respect to the aspects of Paragraph 81 criteria. The drafting team did not get clear consensus with respect to the requirements. The drafting team considered each of the comments and have incorporated those that team found to improve the quality of the standards.

INT-004

- R1: An exception for Pseudo-ties that are already accounted for in congestion management tools was added and the detail on the MW amount to be included on the transaction was eliminated.
- R2: The requirement was revised to apply to only those LSEs that submitted and RFI per R1. The drafting team also simplified the language or R2.1 and R2.2 and R2.3.
- R3: This was removed as an interim registration process was determined to be unnecessary.
- R4: The requirement was modified to require entities to register Pseudo-Ties when the registration process is available in the NAESB Electric Industry Registry (EIR).
- The drafting team added general considerations for curtailment of dynamic transactions to the Guidelines and Technical Basis section of the standard.

INT-006

- R1: This requirement was removed. The entities to receive the transaction are included today in the eTag specification, Section 3.6.1.1.1. The timing requirement for the distribution of tags is removed from this standard, as they are currently included and expected to remain in the NAESB documentation.
- R2, R3: The drafting team revised the language for clarity.
- R4: The drafting team added the specific entities to perform the review.
- R5: No changes. These requirements direct that 'active' approval is required to transition to Confirmed Interchange; that if entities do not approve the transaction that it will not be transitions to Confirmed. If the software were not automatically performing this function, this requirement identifies the logic to be applied.

- R6: No changes. This distribution requirement may currently drive how software performs this function. However, if that software were not present this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the interchange to occur.
- Tables: The drafting team removed columns A and C details as these are no addressed in any requirement. These details remain in the NAESB timing tables.

INT-009

- R1: The drafting team added phrase "by a Reliability Coordinator" to clarify what aspect of INT-010 is applicable to this requirement.
- R2: No change was made to language but language was added to the Rationale.
- R3: This requirement was unchanged and was not removed as suggested by some commenters. Since the Transmission Operator is not a part of the approval process for the Interchange, this requirement is the only means by which they are aware of the need to adjust the HVDC flow.

INT-010

- R1: This language was modified to be consistent with the currently effective requirement. This results in minimal revision to the existing, enforceable requirement.
- R2, R3: The drafting team revised the term "created" to "submitted".
- R4: The drafting team agreed with comments that these are rules for when reliability adjusts should be used and if reliability adjusts were issued for reasons other than this it would not impact reliability. We agree these would be included in the NAESB business and the requirement is removed from the standard.
- R5: The entities to receive the transaction for evaluation are included today in the eTag specification, Section 3.6.1.1.1 so the drafting team has removed this requirement.
- R6: Pseudo-ties were added to the requirement and the language was clarified.
- The drafting team added general considerations for curtailment of dynamic transactions to the Guidelines and Technical Basis section of the standard.

Several entities from the ERCOT area requested exemption from some or all of the standards. When the drafting team reviewed the requirements we did not see that an exemption is required. For example, on INT-011, if ERCOT does not have point-to-point service, the requirement would not apply and an exemption is not needed. However, when we look at INT-006, if ERCOT is involved in a transaction outside its area, all of these requirements would apply.

Proposed Revisions or Additions to NERC Glossary of Terms

1. Proposed revisions to approved NERC Glossary terms:
    a. **Adjacent Balancing Authority** - A Balancing Authority Area that is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
    Existing definition: A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
    b. **Intermediate Balancing Authority -** A Balancing Authority involved in an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
    Existing Definition: A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.
    c. **Dynamic Schedule:** A time-varying energy transfer that is updated in real time and included in the Net Interchange Scheduled term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
    Existing definition: A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
    d. **Pseudo-tie:** A time-varying energy transfer that is updated in real time and included in the Net Interchange Actual term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).
    Existing definition: A telemetered reading or value that is updated in real time and used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
    e. **Request for Interchange (RFI) -** A collection of data as defined in the NAESB Business Practice Standards, to be submitted to the Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.
    Existing definition: A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.
    f. **Arranged Interchange** - The state where the Sink Balancing Authority has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).
    Existing definition: The state where the Interchange Authority has received the Interchange information (initial or revised).
    g. **Confirmed Interchange** - The state where the Sink Balancing Authority has verified the Arranged Interchange.
    Existing definition: The state where the Interchange Authority has verified the Arranged Interchange.

h. **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule.
Existing Definition: The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)

i. **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for the resulting Interchange Schedule.
Existing Definition: The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)

2. Proposed new NERC Glossary terms:

Composite Confirmed Interchange – The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.

Attaining Balancing Authority - A Balancing Authority bringing generation or load into its effective control boundaries through a dynamic transfer from the Native Balancing Authority.

Native Balancing Authority - A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a dynamic transfer.

Reliability Adjustment Arranged Interchange - Request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

3. Additional terms revised to address FERC directives:

The CISDT had previously posted proposed requirements to address FERC Order 693, Paragraph 866. These proposed Transmission Operator and Reliability Coordinator requirements related to review of Confirmed Interchange prior to implementation. The CISDT received feedback from stakeholders as well the NERC Operating Committee that the proposed requirements were not necessary as this review was already addressed in other standards. The CISDT reviewed those standards and Interchange is not explicitly noted. The team feels that additional revisions are necessary to meet the directive. Rather than revise requirements, the CISDT is proposing revisions to defined terms as they apply to existing standards. These terms are Operational Planning Analysis and Real-time Assessment:

Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

This defined term is used in existing IRO-008-1 (Reliability Coordinator Operational Analyses and Real-time Assessments) and proposed TOP-002-3 (Operations Planning). In IRO-008-

1, Requirement R1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider interchange when performing the study. Further, Requirement R2 specifies that the Reliability Coordinator must perform a Real-time Assessment. Again, by explicitly including "Interchange" in the definition of Real-time Assessment, the Reliability Coordinator must consider interchange when performing the study. When the results of either of these studies indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3. TOP-002-3 contains requirement for the Transmission Operator to perform an Operational Planning Analysis (R1), develop plans for reliable operations based on the results of the Operational Planning Analysis and to notify other entities as to their role in those plans (R3).

NOTE: The following Summary Consideration and individual responses was developed prior to the July – August 2013 posting.

The Coordinate Interchange Standard Drafting Team thanks all commenters who submitted comments on the current drafts of INT-004-3, INT-006-4, INT-009-2, INT-010-2, and INT-011-1. These standards were posted for a 30-day public comment period from November 10, 2009 through December 11, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 30 sets of comments, including comments from more than 100 different people from over 60 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Stakeholders offered several supportive comments, and identified areas where the team needed to do additional work. In addition to minor changes related to typographical and organizational errors, the team made the following significant changes:

Removed the definition of "Interchange Coordination" from the proposed standards.

Proposed removal of the following definitions from the NERC Glossary:

Reliably Adjustment RFI

Interchange Authority

Proposed addition of the following definitions to the NERC Glossary:

Composite Confirmed Interchange

Proposed modification to the following definitions in the NERC Glossary:

Arranged Interchange

Confirmed Interchange

Request for Interchange

Clarified and streamlined distribution requirements.

Modified approval criteria to ensure they were assigned to the right entities with the right information.

Removed the approval criteria for the Transmission Service Provider that implied "pre-emptive" curtailment.

Modified the denial criteria for reliability-based requests such that denials are only acceptable if an approval would cause a violation of a NERC standard.

Removed the proposed Transmission Operator and Reliability Coordinator requirements related to review of Confirmed Interchange prior to implementation. Instead, to address the FERC directive, the team is proposing revisions to defined terms as they apply to existing standards. These terms are Operational Planning Analysis and Real-time Assessment:

Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Real-time Assessment: An examination of existing and expected system conditions, including Interchange, conducted by collecting and reviewing immediately available data.

These defined terms are used in existing IRO-008-1 (Reliability Coordinator Operational Analyses and Real-time Assessments) and proposed TOP-002-3 (Operations Planning). In IRO-008-1, Requirement R1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider interchange when performing the study. Further, Requirement R2 specifies that the Reliability Coordinator must perform a Real-time Assessment. Again, by explicitly including "Interchange" in the definition of Real-time Assessment, the Reliability Coordinator must consider interchange when performing the study. When the results of either of these studies indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3. TOP-002-3 contains requirement for the Transmission Operator to perform an Operational Planning Analysis (R1), develop plans for reliable operations based on the results of the Operational Planning Analysis and to notify other entities as to their role in those plans (R3).

Added a new standard to address the FERC directive in Order No. 693 regarding the treatment of non-firm point-to-point service used for intra-balancing authority transfers.

Some commenter's had some objections that the team considered and ultimately decided did not merit changes to the standard. The following summarizes these positions, and explains why the team chose to not act on them.

Some entities expressed concern regarding the removal of the IA from the standards. Interchange is an operational responsibility associated with balancing, and the SDT believes that ensuring that Interchange is coordinated is an appropriate responsibility for the Balancing Authority. However, the SDT does not believe that the IA needs to be removed from the Functional Model. The SDT believes that it is more correct to say that the Sink BA is being mandated to take on the responsibility of performing the IA functions or delegating the IA tasks as they deem appropriate. To the extent that another user/owner/operator of the BES wishes to perform this function, developing a JRO with one or more registered entities is appropriate. If a registered Balancing Authority wishes to delegate these tasks to another entity that is not a user/owner/operator of the BES, then they may elect to contractually delegate that function by mutual agreement (but with the entity providing that function not the responsibility for that function to be performed).

Some commenters suggested that the standards should address Inadvertent Interchange. The SDT responded that Inadvertent Interchange is outside the scope of the standard.

Some commenters suggested that market operators should be allowed to make reliability-based adjustments to interchange for commercial reasons. The SDT disagreed, and responded that those adjustments should instead be handled through non-reliability-based adjustments.

One commenter suggested that the requirements were unclear, since they required BAs to "agree," but did not assign blame to a single entity if parties do not agree. The SDT disagreed, and said the standard was clear: failing to reach agreement was a failure of both parties.

All comments submitted may be reviewed in their original format on the standard's project page.

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, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

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.	Group	Jim Cyrulewski, Chairman	Functional Model Working Group	X	X	X	X	X					X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jerry Rust	NWPP Corp	WECC	10
2.	H. Steven Myers	ERCOT	ERCOT	2
3.	Peter Heidrich	FRCC	FRCC	10
4.	Ben Li	Ben Li Assoc	NPCC	2
5.	Guy V. Zito	NPCC	NPCC	10
6.	Thomas Bradish	RRI Energy	SERC	5
7.	Albert DiCaprio	PJM	RFC	2
8.	Peter Munn	Air Liquide	MRO	5
9.	Dana Showalter	ERCOT	ERCOT	2
10.	Karl Tammar	Northeast Utilities	NPCC	1
11.	John Walewski	Hydro One	NPCC	5
12.	Mike Yelland	IESO	NPCC	2
13.	Anthony Jankowski	We Energies	SPP	5
14.	John Simpson	RRI Energy	ERCOT	1
15.	Dennis Chastain	TVA	SERC	9
16.	Gary Dawes	Colorodo River Commission	WECC	9

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
17. Michael Gildea	Dominion	SERC	1										
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Brian D. Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	David Kiguel	Hydro One Networks Inc.	NPCC	1
12.	Michael R. Lombardi	Northeast Utilities	NPCC	1
13.	Randy MacDonald	New Brunswick System Operator	NPCC	2
14.	Greg Mason	Dynegy Generation	NPCC	5
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Ralph Rufrano	New York Power Authority	NPCC	5
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
22.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
23.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Jim Case	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Thomas	IMEA	SERC	3, 4, 9

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

2.	Brad Young	EON.US	SERC	1, 3, 5
3.	Eugene Warnecke	Ameren	SERC	1, 3
4.	David McRee	Duke	SERC	1, 3, 5
5.	Steven Belle	SCE&G	SERC	5, 1, 3
6.	Gary Hutson	SMEPA	SERC	1, 3, 5, 9
7.	Pat McGovern	GTC	SERC	1
8.	Paul Turner	GSOC	SERC	1, 3, 5
9.	Chad Randall	EON.US	SERC	1, 3, 5
10.	Troy Blalock	SCE&G	SERC	1, 3, 5
11.	Steve Hebert	SCE&G	SERC	1, 3, 5
12.	Steve McElhaney	SMEPA	SERC	1, 3, 5, 9
13.	Alvis Lanton	SIPC	SERC	1, 3, 5, 9
14.	John Troha	SERC	SERC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Deb Schaneman	Platte River Power Authority	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carol Ballantine	Platte River Power Authority	WECC	1, 3, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Melinda Montgomery	Entergy	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeremy West	Entergy	SERC	1
2.	Clint Aymond	Entergy	SERC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Patrick Brown	PJM		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Albert DiCaprio	PJM	RFC	2
2.	William Harm	PJM	RFC	2
3.	Thomas Moleski	PJM	RFC	2
4.	Mark Kuras	PJM	RFC	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Wes Hutchison	Transmission Operational Analysis & Support	WECC	1
2.	Correne Surface	Transmission Operational Analysis & Support	WECC	1
3.	Jamie Murphy	Transmission Technical Operations	WECC	1
4.	Fran Halpin	Power Duty Scheduling	WECC	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dave Folk	FE	RFC	1, 3, 4, 5, 6
2.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Guy Andrews	GSOC & GTC Response			X	X						

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jason Snodgrass	Georgia Transmission Corp	SERC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Jason L. Marshall	Midwest ISO Stakeholder Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe O'Brien	NIPSCO	RFC	1
2.	Joe Knight	Great River Energy	MRO	3, 4, 5, 6
3.	Michael Ayotte	ITC Holdings	RFC	1

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck Lawrence	American Transmission Company	MRO	1
2.	Tom Webb	Wisconsin Public Service	MRO	3, 4, 5, 6
3.	Terry Bilke	Midwest ISO Inc.	MRO	2
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6									
9.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6									
10.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6									
11.	Scott Nickels	Rochester Public Utilties Address	MRO	4									
12.	Terry Harbour	MidAmerican Energy Company	MRO	6, 1, 3, 5									
12.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
13.	Individual	Nicholas Browning	Midwest ISO		X								
14.	Individual	John Cummings	PPL Energy Plus					X					
15.	Individual	Gerry Adamski	NERC Staff										
16.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
17.	Individual	James Starling	South Carolina Electric and Gas	X		X		X					
18.	Individual	Angela P. Gaines	San Diego Gas & Electric	X		X		X					
19.	Individual	Steve Alexanderson	Central Lincoln			X							
20.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
21.	Individual	Darcy O'Connell	California ISO		X								
22.	Individual	Louise McCarren	WECC										X
23.	Individual	Kirit Shah	Ameren	X		X		X	X				
24.	Individual	Leland McMillan	NorthWestern Energy	X		X		X					
25.	Individual	Marcus Lotto	Southern California Edison Co.	X		X		X	X				
26.	Individual	Ron Gunderson	Nebraska Public Power District	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
27.	Individual	James H. Sorrels, Jr.	American Electric Power (AEP)	X		X		X	X				
28.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
29.	Individual	Kathleen Goodman	ISO New Enlgand Inc.		X								
30.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. Do you agree that the "two phase" approach (in which the IA issues, 693 directives, and E-Tag relationship are addressed in a first phase, followed by a second phase to address dynamic transfers and backup plans) is appropriate? If no, what do you believe the correct approach should be?

Summary Consideration: The majority of commenters agree with the "two phase" approach. Since the project was placed on inactive status for approximately two years, the drafting team has revised its approach and will be addressing all aspects of the project at the same time.

Organization	Yes or No	Question 1 Comment
Ameren		
Central Lincoln		
Functional Model Working Group		
Nebraska Public Power District		
PPL Energy Plus		
South Carolina Electric and Gas		
Xcel Energy		
Duke Energy	Agree	
Entergy	Agree	
GSOC & GTC Response	Agree	
Independent Electricity System Operator	Agree	
ISO New Enlgand Inc.	Agree	

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Agree	
Midwest ISO	Agree	
Midwest ISO Stakeholder Standards Collaborators	Agree	
NERC Staff	Agree	
MRO NERC Standards Review Subcommittee	Agree	
NorthWestern Energy	Agree	
PacifiCorp	Agree	
Platte River Power Authority	Agree	
San Diego Gas & Electric	Agree	
SERC OC Standards Review Group	Agree	
Southern California Edison Co.	Agree	
WECC	Agree	
American Electric Power (AEP)	Disagree	
Bonneville Power Administration	Disagree	Dynamic Transfers should be addressed in a single standard. All dynamic transfers have an impact on the grid and should be treated equally and simultaneously in standards development. Addressing dynamic schedules while leaving pseudo ties out of the requirements leaves a huge hole in the standard. Standards dynamic schedules and pseudo ties should be developed in a single phase. Please advise the CI SDT to be cognizant of the downstream effects that multiple Standard revisions create. Each time a new Standard version is issued, staff responsible for demonstrating compliance is required to provide documentation covering each period of time within the calendar year that each version is in effect. Multiple Standard versions within a calendar year create a lot of documentation efforts. Please limit versions to the minimum

Organization	Yes or No	Question 1 Comment
		number possible.
Response: The CISDT has addressed dynamic transfers in the revised standards.		
Northeast Power Coordinating Council	Agree	It is not clear what the second phase is. Backup plans only appear in BAL-005.
Response: The CISDT has addressed the full scope of the SAR in the latest posted version the standards.		
PJM	Disagree	The phased in approach is neither good nor bad. PJM however would suggest a simplified approach:- Stick to the basics for writing reliability requirements related to coordinating Interchange - i.e. RFI approval is required before implementation (no approval, no implementation)- make a clear distinction between tools (e-Tag) and entities- treat all RFIs the same no matter HOW they get implemented (i.e. dynamic schedules should be treated in the same way as normal schedules with regards to confirmation - and leave the Business rules to NAESB and the Markets)Regarding Dynamic Transfers, NERC needs to make clear that Dynamic Transfers are simply a means of implementing a Confirmed Interchange. A pseudo-tie is identical to a dynamic schedule and is not a means to avoid reserving transmission for a given point-to-point transaction.
Response: The SDT believes that the key information suggested is included in INT-009. However, the SDT also feels that the additional information included in the other standards is of value, and should not be eliminated. We agree that a Pseudo-Tie should not be used to avoid purchasing transmission service.		
California ISO	Disagree	The present INT Reliability Standards could use some “polishing” to eliminate redundancy and consolidate some Requirements, however, this SDT initiative seems to be primarily/solely(?) focused upon eliminating the IA function and responsibility, which is not appropriate, and which the CISO does NOT support.
Response: The intent is not to eliminate the IA function and responsibility, but to assign the tasks to a specific entity.		
FirstEnergy	Agree	We agree with the two phase approach. However, we ask for clarification: Does this mean the SDT will ballot the first phase standards and obtain FERC approval while working on phase two?
Response: The CISDT has addressed the full scope of the SAR in the latest posted version the standards.		

2. As discussed above, the CI SDT believes that the IA is not an actual entity, but a function that is performed by the Sink Balancing Authority. This approach has been reviewed with the leadership of the Functional Model Working Group, which has agreed that the INT standards assigning those functions to the Sink Balancing Authority directly would not conflict with the functional model. Accordingly, the team is proposing to remove the IA from these standards. Do you agree with the IA being removed from these standards? If no, please explain why you believe the IA should be retained.

Summary Consideration: The majority of commenters agreed with removing the IA from the standards.

Some entities expressed concern regarding the removal of the IA from the standards. Interchange is an operational responsibility associated with balancing, and the SDT believes that ensuring that Interchange is coordinated is an appropriate responsibility for the Balancing Authority. However, the SDT does not believe that the IA needs to be removed from the Functional Model. The SDT believes that it is more correct to say that the Sink BA is being mandated to take on the responsibility of performing the IA functions or delegating the IA tasks as they deem appropriate. To the extent that another user/owner/operator of the BES wishes to perform this function, developing a JRO with one or more registered entities is appropriate. If a registered Balancing Authority wishes to delegate these tasks to another entity that is not a user/owner/operator of the BES, then they may elect to contractually delegate that function by mutual agreement (but with the entity providing that function not the responsibility for that function to be performed).

Organization	Yes or No	Question 2 Comment
Ameren		
Central Lincoln		
South Carolina Electric and Gas		
Bonneville Power Administration	Agree	
Entergy	Agree	
FirstEnergy	Agree	
GSOC & GTC Response	Agree	

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	Agree	
Midwest ISO	Agree	
Midwest ISO Stakeholder Standards Collaborators	Agree	
Nebraska Public Power District	Agree	
NERC Staff	Agree	
MRO NERC Standards Review Subcommittee	Agree	
PacifiCorp	Agree	
Platte River Power Authority	Agree	
PPL Energy Plus	Agree	
Southern California Edison Co.	Agree	
Xcel Energy	Agree	
San Diego Gas & Electric	Agree	At present, there appears to be no issues with removing IA from these standards. However, in doing so, an expanded or new definition of BA should be developed that incorporates the functions originally assigned to the IA to insure clarity within the INT standards themselves, as well as any other standard where the BA adopts the IA functionality.
Response: Thank you for your supportive comment. The SDT does not believe that the IA needs to be removed from the Functional Model. The SDT believes that it is more correct to say that the Sink BA is being mandated to take on the responsibility of performing the IA functions or delegating the IA tasks as they deem appropriate.		
American Electric Power (AEP)	Disagree	Currently, there are applicable entities in the NERC functional model which are registered as IAs. We believe that the current process is not broken and that the IA just needs to be better defined. Note: Please refer to question 17 for additional comments on the rewrite of the Standards.

Organization	Yes or No	Question 2 Comment
Response: The SDT believes that the Interchange Authority is a function that must be assigned to a user/owner/operator of the BES. Interchange is an operational responsibility associated with balancing, and we believe that ensuring that Interchange is coordinated is an appropriate responsibility for the Balancing Authority. While we agree other entities may be capable of performing this function, we do not believe that an entity other than the Balancing Authority should be responsible for ensuring that Interchange is coordinated. We further believe that unless a specific Balancing Authority that is invested in the outcome of the coordination process is assigned the responsibility for it, there is no way to ensure that Interchanges is accurately and reliably coordinated. This eliminates the need to require specific entities to register as IAs. It is our belief that the need to register IAs will be eliminated once the standards are approved. However, the SDT does not believe that the IA needs to be removed from the Functional Model. The SDT believes that it is more correct to say that the Sink BA is being mandated to take on the responsibility of performing the IA functions or delegating the IA tasks as they deem appropriate.		
Independent Electricity System Operator	Agree	From a practical standpoint, we agree with this change on the basis that this does not conflict with the Functional Model. However, this may create a problem if and when an entity steps forward to register as the IA and perform the IA functions. We suggest the SDT consider reverting back to the existing applicability and assign this to the IA, but specifies that given there are no entities registered as the IA and the default is the sink BA, all BAs are required to perform the IA function and hence need to register as one.
Response: The SDT believes that the Interchange Authority is a function that must be assigned to a user/owner/operator of the BES. Interchange is an operational responsibility associated with balancing, and we believe that ensuring that Interchange is coordinated is an appropriate responsibility for the Balancing Authority. While we agree other entities may be capable of performing this function, we do not believe that an entity other than the Balancing Authority should be responsible for ensuring that Interchange is coordinated. We further believe that unless a specific Balancing Authroity that is invested in the outcome of the coordination process is assigned the responsibility for it, there is no way to ensure that Interchanges is accurately and reliably coordinated. This eliminates the need to require specific entities to register as IAs. It is our belief that the need to register IAs will be eliminated once the standards are approved. However, the SDT does not believe that the IA needs to be removed from the Functional Model. The SDT believes that it is more correct to say that the Sink BA is being mandated to take on the responsibility of performing the IA functions or delegating the IA tasks as they deem appropriate. **To the extent that another user/owner/operator of the BES wishes to perform this function, developing a JRO with one or more registered entities is appropriate.** **If a registered Balancing Authority wishes to delegate these tasks to another entity that is not a user/owner/operator of the BES, then they may elect to contractually delegate that function by mutual agreement (but with the entity providing that function not the responsibility for that function to be performed).**		
NorthWestern Energy	Agree	NorthWestern is concerned that BAs would have to accept the role of the IA. A Balancing Authority should not be held responsible for timing that is at the mercy of the software provider, Internet traffic, etc.

Organization	Yes or No	Question 2 Comment
Response: The SDT has made modifications to INT-006 to address only the cases where a reliability problem is created when timelines are not met.		
PJM	Disagree	PJM does not agree that the IA should be removed from the standards. It should be noted that none of the NERC and FERC approval functional entities are "actual entities" until a corporate entity registers (or is registered) by NERC to comply with the standards written to the respective functions. The FM and the FMWG has consistently stated that the default position is that if no entity registers as an IA, then the Regional Entity must register someone and it is reasonable that the sink BA will be held responsible for the IA requirements. The SDT must address the issue that a software checkout tool is a means of checkout and is not the functional entity itself. PJM does agree that the failure of an INTERCONNECTION-WIDE tool should not be considered as non-compliance for the respective sink BA. The SDT should continue to seek consensus on rewording the standard such that BA compliance is based on the information provided to it (i.e. if the tool incorrectly provides confirmation on an Arranged Interchange (AI), and the BA acts in good faith on that information, then the requirement should recognize that the BA is compliant when it Implements that AI.)That does not mean that no one is responsible for checkout. A BA should never be excused from only implementing AIs that it knows or is informed has been confirmed. If there is no such knowledge or third-party confirmation, then there can not be any implementation of such not confirmed schedules.
Response: The SDT believes that the Interchange Authority is a function that must be assigned to a user/owner/operator of the BES. Interchange is an operational responsibility associated with balancing, and we believe that ensuring that Interchange is coordinated is an appropriate responsibility for the Balancing Authority. While we agree other entities may be capable of performing this function, we do not believe that an entity other than the Balancing Authority should be responsible for ensuring that Interchange is coordinated. We further believe that unless a specific Balancing Authority that is invested in the outcome of the coordination process is assigned the responsibility for it, there is no way to ensure that Interchanges is accurately and reliably coordinated. This eliminates the need to require specific entities to register as IAs. It is our belief that the need to register IAs will be eliminated once the standards are approved. However, the SDT does not believe that the IA needs to be removed from the Functional Model. The SDT believes that it is more correct to say that the Sink BA is being mandated to take on the responsibility of performing the IA functions or delegating the IA tasks as they deem appropriate. **The SDT also believes this addresses the practical issue of deciding which entity will provide the IA function for each transaction. From a practical perspective, IA duties today have been assigned to the Sink BA; however nothing in the standards or functional model prohibits a PSE from requesting an entity other than the sink BA to perform those IA functions. This can raise conflicts where there are multiple IAs associated with each transaction and the current functional model and standards do not address 'which' IA is responsible. In addition, the current functional model and standards would allow .for an entity to ask WECC to provide IA services for a transaction flowing from Duke to Southern Company. To do so would be inappropriate since WECC does not have the system and reliability information to evaluate the transaction. To resolve these ambiguities the SDT has assigned the functional model IA responsibilities clearly to the Sink BA. Note that this does not prohibit a BA from mutually entering into a contract with another entity to provide the IA functions.** **The commenter states, "The FM and the FMWG has consistently stated that the default position is that if no entity registers as an IA, then the Regional**		

Organization	Yes or No	Question 2 Comment
Entity must register someone and it is reasonable that the sink BA will be held responsible for the IA requirements." The SDT does not agree that this is reasonable – the standards should assign the responsibility to an appropriate entity, not rely on the Regional Entity to make arbitrary assignments. The SDT does agree that it is reasonable for the sink BA to be the entity that is assigned the responsibility, and has done so in its draft standards. **To the extent that another user/owner/operator of the BES wishes to perform this function, developing a JRO with one or more registered entities is appropriate.** **If a registered Balancing Authority wishes to delegate these tasks to another entity that is not a user/owner/operator of the BES, then they may elect to contractually delegate that function by mutual agreement (but with the entity providing that function not the responsibility for that function to be performed).**		
Functional Model Working Group	Disagree	The Functional Model Working Group (FMWG) does not agree with removing the IA from the NERC standards. The FMWG would like to make clear what is meant with the statement "... assigning those functions to the Sink Balancing Authority directly would not conflict with the functional model" The FMWG has clearly articulated in the Functional Model Report and in the associated Functional Model Technical Report that the Functional Model does not in any way presume to direct the Registration process associated with NERC Reliability Standards. The Functional Model itself identifies independent tasks that can be accomplished by independent entities. The IA is one such set of independent tasks. That set of tasks has been and continues to be a required "function". The FMWG wants to make clear that the IA function is regarded as a critical reliability function and should not be removed. Regarding registration, the FMWG does not regard registering NERC-registered Balancing Authorities (BA) as IAs to be in conflict with the Functional Model. The FMWG would note that "Each BA may be an IA; but not every IA needs to be a BA." There is a significant difference between the two ideas. It should be noted that none of the NERC and FERC-approval functional entities are "actual entities" until a corporate entity registers (or is registered) by NERC to comply with the standards written to the respective functions. The SDT misconstrues the issue. The FMWG agrees with the NERC Regions' default position is that if no entity registers as an IA, then the sink BA will be held responsible for the IA requirements. The lessons learned when NERC was operating under voluntary policies was that if a set of functions can be served independently; ultimately some entity will fill that position. The fact that the IA functions have the potential to be served by a corporate entity that does not need to fill all of the NERC BA requirements indicates the need to separate the tasks from the BAs. That does not mean that in the absence of such a corporate entity, that the BAs (as a default position) cannot be assigned to be compliant with the IA tasks. To return to a blanket assignment of the IA tasks to the BA is to ignore the lessons of the history of NERC. Lastly, there is no issue with requiring BAs to comply with the tasks defined for the IA. The original confusion was/is with the concept that a delegated (non-registered) third-party is providing the IA functions. However, to

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>eliminate the reference to IA and to place the same tasks under the BA does nothing to rectify that issue/non-issue.

However, the elimination of IA will mean that in the future when a corporate entity does want to register to do those tasks that entity will by necessity have to be a BA. Thus it can be seen that eliminating IA is not the same as requiring BAs to comply with the IA functions.</td></tr>
<tr><td colspan="3">Response: The SDT agrees that the IA tasks must be done, and should not be removed from the model or the standards.

The commenter states, “The FM and the FMWG has consistently stated that the default position is that if no entity registers as an IA, then the Regional Entity must register someone and it is reasonable that the sink BA will be held responsible for the IA requirements.” The SDT does not agree that this is reasonable – the standards should assign the responsibility to an appropriate entity, not rely on the Regional Entity to make arbitrary assignments. The SDT does agree that it is reasonable for the sink BA to be the entity that is assigned the responsibility, and has done so in its draft standards.

The SDT believes that the Interchange Authority is a function that must be assigned to a user/owner/operator of the BES. Interchange is an operational responsibility associated with balancing, and we believe that ensuring that Interchange is coordinated is an appropriate responsibility for the Balancing Authority. While we agree other entities may be capable of performing this function, we do not believe that an entity other than the Balancing Authority should be responsible for ensuring that Interchange is coordinated. We further believe that unless a specific Balancing Authority that is invested in the outcome of the coordination process is assigned the responsibility for it, there is no way to ensure that Interchanges is accurately and reliably coordinated. This eliminates the need to require specific entities to register as IAs. It is our belief that the need to register IAs will be eliminated once the standards are approved. However, the SDT does not believe that the IA needs to be removed from the Functional Model. The SDT believes that it is more correct to say that the Sink BA is being mandated to take on the responsibility of performing the IA functions or delegating the IA tasks as they deem appropriate.

To the extent that another user/owner/operator of the BES wishes to perform this function, developing a JRO with one or more registered entities is appropriate. If a registered Balancing Authority wishes to delegate these tasks to another entity that is not a user/owner/operator of the BES, then they may elect to contractually delegate that function by mutual agreement with the entity providing that function (but not the responsibility for that function to be performed).

As such, it is not necessary for an entity wishing to provide IA/IC services to be a BA. If the entity is a user/owner/operator of the BES, they may enter into a JRO with one or more responsible entities (BAs); if not, they may offer IA/IC services that can be contractually arranged for by the responsible entity (BA).</td></tr>
<tr><td>California ISO</td><td>Disagree</td><td>The IA IS an actual entity and must be, as Interchange management tracking tools (like the Western Interchange Tool or WIT for the WECC) are inanimate objects, and not capable of cognitive thought. The responsible party (IA) is the owner or operator of the tool, not the tool itself. The IA uses ITS tools to accomplish and fulfill its IA functional model role. In the West, the IA is the RRO, WECC, by way of 36 bilateral contracts.</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
		The California ISO believes the proposed NERC INT Standard changes advance substantial changes to the present Interchange Schedule standards and move away from the central coordinating responsibility of the Interchange Authority (IA), in our case WECC, which uses the WIT as the IA monitoring tool. Each of the BAs within the WECC helped develop and pay for development of the WIT. This IA function has worked well over the past two years, with clear lines of authority and responsibility, as documented in the IA contract with the RRO. When asked “what changes” with the SDT draft revisions, the answers to hardware? Software? Liability? Were all 3 nothing” responses. As such, we would oppose any movement away from the defined IA role, absent some substantive justification. WECC (as our IA in the West) and the WIT are the Interchange Authority and definitive keeper of all Implemented Interchange documentation, respectively. The Interchange Authority is an entity, and cannot be software. WECC was selected as the IA for the West and uses WIT as its IA tool. The CISO would not support movement away from IA authority towards dispersed Sink BA authority. You cannot have 37 BAs all responsible in the role of an IA to tell the other 36 what to do. Arranged Interchange must be mutually agreed upon and checked out, with oversight by the RRO as the IA. – At present, the CISO has an IA services contract in place with WECC for this purpose. We strongly support use of the WECC WIT by all WECC entities. These proposed significant NERC Standard changes are contrary to the concept of the IA, and thus to the WIT as the definitive repository for arranged interchange. Further, it seems like an inefficient use of time to revisit the issue of the IA definition and role, especially so given the fact that this issue was previously resolved within the West by the WECC Interchange Scheduling Committee and the WECC Board, establishing the WECC, our RRO as our IA for the West. All 37 BAs negotiated and entered into IA contracts with WECC in this IA capacity accordingly in December 2008.The CISO supported and continues to support this convention, the present NERC IA definition and has been very pleased with the WIT as the WECC IA Tool as the definitive source of documentation for checked out NSI and NAI. With so many other critical matters before us, it seems an inefficient use of time to reopen a construct that is serving us well.

Response: The SDT believes that the Interchange Authority is a function that must be assigned to a user/owner/operator of the BES. Interchange is an operational responsibility associated with balancing, and we believe that ensuring that Interchange is coordinated is an appropriate responsibility for the Balancing Authority. While we agree other entities may be capable of performing this function, we do not believe that an entity other than the Balancing Authority should be responsible for ensuring that Interchange is coordinated. We further believe that unless a specific Balancing Authroity that is invested in the outcome of the coordination process is assigned the responsibility for it, there is no way to ensure that Interchanges is accurately and reliably coordinated. This eliminates the need to require specific entities to register as IAs. It is our belief that the need to register IAs will be eliminated once the standards are approved. However, the SDT does not believe that the IA needs to be removed from the Functional Model. The SDT believes that it is more correct to say that the Sink BA is being mandated to take on the responsibility of performing the IA functions or

Organization	Yes or No	Question 2 Comment
delegating the IA tasks as they deem appropriate. **To the extent that another user/owner/operator of the BES wishes to perform this function, developing a JRO with one or more registered entities is appropriate. If a registered Balancing Authority wishes to delegate these tasks to another entity that is not a user/owner/operator of the BES, then they may elect to contractually delegate that function by mutual agreement (but with the entity providing that function not the responsibility for that function to be performed).** **This would not eliminate the possibility for the existence of tools like the WIT, or the manner it which the WIT is currently provided. To the extent that WECC and its member BAs still wish to utilize a central tool like the WIT, we believe that the proposed standards allow it.**		
Northeast Power Coordinating Council	Disagree	This does conflict with the Functional Model. This may create a problem if and when an entity steps forward to register as the IA and perform the IA functions. We suggest the SDT consider reverting back to the existing applicability and assign this to the IA, but specify that given there are no entities registered as the IA and the default is the sink BA, all BAs are required to perform the IA function and hence need to register as one.
Response: The SDT believes that the Interchange Authority is a function that must be assigned to a user/owner/operator of the BES. Interchange is an operational responsibility associated with balancing, and we believe that ensuring that Interchange is coordinated is an appropriate responsibility for the Balancing Authority. While we agree other entities may be capable of performing this function, we do not believe that an entity other than the Balancing Authority should be responsible for ensuring that Interchange is coordinated. We further believe that unless a specific Balancing Authority that is invested in the outcome of the coordination process is assigned the responsibility for it, there is no way to ensure that Interchanges is accurately and reliably coordinated. This eliminates the need to require specific entities to register as IAs. It is our belief that the need to register IAs will be eliminated once the standards are approved. However, the SDT does not believe that the IA needs to be removed from the Functional Model. The SDT believes that it is more correct to say that the Sink BA is being mandated to take on the responsibility of performing the IA functions or delegating the IA tasks as they deem appropriate. **To the extent that another user/owner/operator of the BES wishes to perform this function, developing a JRO with one or more registered entities is appropriate. If a registered Balancing Authority wishes to delegate these tasks to another entity that is not a user/owner/operator of the BES, then they may elect to contractually delegate that function by mutual agreement (but with the entity providing that function not the responsibility for that function to be performed).**		
ISO New Enlgand Inc.	Agree	We agree that assigning the standard requirements, as suggested, to the Sink BA does not conflict with the functional model. Since there may be more than one Interchange Coordinator, the assignment of these requirements to the Sink BA provides clear guidance to the industry on the entities that are responsible for these functions and does not raise additional questions of interpretation that the assignment to the IC could create.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your supportive comment.		
Duke Energy	Agree	We agree with removing the IA. However does elimination of the IA place more compliance responsibility on the Sinking BA? And is the Sinking BA the appropriate entity? As opposed to the Purchasing Selling Entity, for example?
Response: Thank you for your supportive comment. We believe it is appropriate for this to be a BA function, as it is directly related to balancing. As the recipient of the energy, we believe that the sink BA is appropriate to ensure the transaction is processed correctly.		
SERC OC Standards Review Group	Agree	We completely agree: The IA should never have been coined as a term of art in NERC discussions.
Response: Thank you for your supportive comment.		
WECC	Agree	WECC supports the removal of the IA from the INT standards. WECC agrees that in the currently effective Functional Model and INT standards, the IA is not an actual entity (user, owner or operator of the bulk electric system) and strongly supports the direction of the CISDT. Corresponding edits to other standards, such as CIP-002 through CIP-009 and IRO-010, should also be made to reflect the removal of the IA.
Response: Thank you for your supportive comment.		

3. As a part of removing the IA from these standards, the CI SDT defined a new term that is used in the purpose statement of INT-011-1:

> **Interchange Coordination** – The act of using commonly available tools to ensure that the transfer of energy from one Balancing Authority to another is undertaken with full disclosure to all the parties involved

Given the term's use in the INT-011-1 purpose, do you agree with this definition? If no, please explain your answer.

Summary Consideration: The majority of the entities agreed with the definition. However, those that did not raised concerns that were considered by the team and ultimately led to the removal of the definition.

Organization	Yes or No	Question 3 Comment
Ameren		
Central Lincoln		
South Carolina Electric and Gas		
Bonneville Power Administration	Agree	
Duke Energy	Agree	
Entergy	Agree	
GSOC & GTC Response	Agree	
Manitoba Hydro	Agree	
Midwest ISO	Agree	
Midwest ISO Stakeholder Standards Collaborators	Agree	
Nebraska Public Power District	Agree	
NERC Staff	Agree	

Organization	Yes or No	Question 3 Comment
MRO NERC Standards Review Subcommittee	Agree	
NorthWestern Energy	Agree	
PacifiCorp	Agree	
Platte River Power Authority	Agree	
San Diego Gas & Electric	Agree	
SERC OC Standards Review Group	Agree	
Southern California Edison Co.	Agree	
WECC	Agree	
American Electric Power (AEP)	Disagree	
Functional Model Working Group		
Xcel Energy	Agree	Consider including the term “compatible” as part of the description.
Response: The SDT has incorporated the proposed change, and moved the definition directly into the purpose statement based on other comments.		
California ISO	Disagree	Interchange coordination is inherent in the pre, RT and ATF checkout processes facilitated by the IA and the WIT tool in the West. Please see comment for Question #2.
Response: The SDT does not understand if a proposal is being made by the commenter. If a proposal is being made, please feel free to bring it directly to the CISDT for further discussion.		
PPL Energy Plus	Disagree	The definition of “Interchange Coordination” appears only in INT-011 and it needs to be in all INT standards. Further, the definition should specify that a tool cannot be responsible for performance: registered entities are responsible for performance and the responsible entity required to carry-out such performance should be stated clearly in each standard.

Organization	Yes or No	Question 3 Comment
Response: This item is more fully discussed in Question 5.		
FirstEnergy	Disagree	The definition of Interchange Coordination in the standards should be consistent with, build on, and support the definition of Interchange Coordinator in the Functional Model Version 5. Consequently, we suggest the following adjustment to the definition of Interchange Coordination - "The act of using commonly available tools to ensure the communication of Arranged Interchange for reliability evaluation purposes and coordination of implementation of valid and balanced Confirmed Interchange between Balancing Authority Areas including full disclosure to all the parties involved."
Response: The SDT has incorporated the proposed change, and moved the definition directly into the purpose statement based on other comments.		
PJM	Disagree	There is no need for the proposed new term. The SDT introduces a new term (Interchange Coordination) and uses the term in the title but the term is not used anywhere in the requirements. What the term also does is to further confuse the concept of a Task for coordination with the Tool used for coordination.
Response: The SDT has incorporated the definition directly into the purpose statement as suggested.		
Independent Electricity System Operator	Disagree	We do not agree that this defined term is necessary; the concept can be described in the purpose without creating a new definition. However, if the CI SDT decides to maintain this definition, we suggest the SDT coordinate the development of the Interchange Coordination definition with the Functional Model Working Group, which in its FM Version 5 has developed a definition for Interchange and Interchange Coordinator. Having different definitions for similar terms within the NERC documents tend to create confusions.
Response: The SDT has incorporated the definition directly into the purpose statement as suggested.		
Northeast Power Coordinating Council	Disagree	We do not agree that this defined term is necessary; the concept can be described in the purpose without creating a new definition. Suggest the SDT coordinate the development of the Interchange Coordination definition with the Functional Model Working Group, which in its FM Version 5 has developed a definition for Interchange and Interchange Coordinator. Having different definitions for similar terms within the NERC documents tends to create confusion.
Response: The SDT has incorporated the definition directly into the purpose statement as suggested.		
ISO New Enlgand Inc.	Disagree	We do not agree that this defined term is necessary; the desired concept can be described in the purpose

Organization	Yes or No	Question 3 Comment
		without creating a new definition.
Response: The SDT has incorporated the definition directly into the purpose statement as suggested.		

4. As a part of removing the IA from these standards, the CI SDT identified several key tasks that Balancing Authorities, Purchasing Selling Entities, and Transmission Service Providers must be able to accomplish as part of Interchange Coordination. These tasks have been specified in INT-011-1 (due to its length, the list of tasks is not reproduced here). Do you agree that these tasks must be specified in a standard as requirements? If no, please explain you answer.

Summary Consideration: The majority of commenters did not agree with this proposal. Many commenters suggested that this should be transferred to certification. The team agrees that incorporating such requirements in the certification process would improve that process. However, we do not believe it is required. Instead, the information contained in INT-011 was moved to the Guidelines and Technical basis section of INT-006.

Organization	Yes or No	Question 4 Comment
Ameren		
Central Lincoln		
South Carolina Electric and Gas		
Bonneville Power Administration	Agree	
Manitoba Hydro	Agree	
Midwest ISO	Agree	
Midwest ISO Stakeholder Standards Collaborators	Agree	
Nebraska Public Power District	Agree	
MRO NERC Standards Review Subcommittee	Agree	
PacifiCorp	Agree	

Organization	Yes or No	Question 4 Comment
PPL Energy Plus	Agree	
San Diego Gas & Electric	Agree	
Southern California Edison Co.	Agree	
Xcel Energy	Agree	
Functional Model Working Group		
FirstEnergy	Disagree	Fundamentally, the approving and denying of Arranged Interchange is the reliability-related task that initiates a transaction's implementation process. Consequently, that approval process and the implementation process are what need to be included in the standard. The rules concerning the submission of a request are business practices that should be determined by NAESB. The only requirement that a PSE should have a method for providing the Request for interchange electronically and that the information they provide related to that request is accurate and complete.
Response: The SDT believes that it is important to describe the expected methods to be used by both the senders and receivers of information. These concepts are now included in the Guidelines and Technical basis section of INT-006.		
Entergy	Disagree	Having the capability to coordinate interchange more properly belongs in certification, so this standard should be eliminated.
Response: These concepts are now included in the Guidelines and Technical basis section of INT-006 rather than in requirements of a standard.		
PJM	Disagree	Here again, the SDT presumes the need to remove the IA. That question should be asked before proceeding with requirements to replace the task. The tasks listed in INT-011 are business practices not reliability issues. INT-011 is written as a certification requirement. R2 (the main requirement) states that the BA must have the "capability" to do the following. Thus the sub-requirements refer back to capability, they are themselves NOT requirements that must be complied to
Response: These concepts are now included in the Guidelines and Technical basis section of INT-006 rather than in requirements of a standard.		

Organization	Yes or No	Question 4 Comment
NERC Staff	Disagree	INT-011 does not appear to serve any specific reliability purpose, and seems primarily to be focused on requiring the use of software tools and procedures. While we believe there is value in the industry agreeing on a common set of tools and practices related to Interchange coordination, we question if they should be required in a reliability standard and monitored for compliance.
Response: These concepts are now included in the Guidelines and Technical basis section of INT-006 rather than in requirements of a standard.		
Platte River Power Authority	Disagree	Key tasks for Interchange Coordination has a reliability function, however, without defined Measures (TBD) it is difficult to determine how a registered entity will prove compliance during an audit other than demonstrating the use of an electronic tagging system. It seems inherently impossible to meet other INT Standards without the capability to meet the key tasks for Interchange Coordination. Therefore, we don't feel that these tasks must be specified in a standard as a requirement.
Response: These concepts are now included in the Guidelines and Technical basis section of INT-006 rather than in requirements of a standard.		
NorthWestern Energy	Disagree	NorthWestern is concerned that entities would have to accept the role of the IA. These entities should not be held responsible for timing that is at the mercy of the software provider, Internet traffic, etc.
Response: The SDT has made modifications to INT-006 to address only the cases where a reliability problem is created when timelines are not met.		
Northeast Power Coordinating Council	Disagree	Please see the comments to Question 2 above. Standards should be written to drive proper behaviors, not to specify the equipment and staff capabilities. The latter requirements belong to Organization Certification Requirements.(1) The term “desire to” is not needed as it makes the standard not measurable. Suggest to remove it from R1 and R3. (2) The majority of this standard deals with capability, not behavior. Suggest moving the requirements of this standard to Organization Certification Requirements.
Response: These concepts are now included in the Guidelines and Technical basis section of INT-006 rather than in requirements of a standard. **The SDT has removed the references to “desires.”**		

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	Disagree	Standards should be written to drive proper behaviors, not to specify the equipment and staff capabilities. The latter requirements belong to Organization Certification Requirements. Further, the term "desire to" is not needed as it makes the standard not measurable. Suggest removing it from R1 and R3.
Response: These concepts are now included in the Guidelines and Technical basis section of INT-006 rather than in requirements of a standard. **The SDT has removed the references to "desires."**		
American Electric Power (AEP)	Disagree	The different RTO and Market models across the BES compromise the intent of the Standard and Requirements. As a result, they are not properly represented with what actually takes place in the Interchange Scheduling process. Also, they do not address the current involvement of PSE or CPSE relationship to the BAs. Note: Please refer to question 17 for additional comments on the rewrite of the Standards.
Response: The CISDT believes that, regardless of market model, Interchange between BAs currently is accomplished through the processes specified in the standards.		
GSOC & GTC Response	Disagree	The requirements as listed in the standard are not to perform the tasks, but to be capable of performing them. This standard reads more like a list of requirements for certification rather than a measure of compliance. It's misplaced as a standard.
Response: These concepts are now included in the Guidelines and Technical basis section of INT-006 rather than in requirements of a standard.		
California ISO	Disagree	There are problems in this standard: R1.1 - "Load Balancing Authority" should be replaced with the defined term "Sink Balancing Authority" as defined in the NERC Glossary. **The SDT has replaced the language as suggested.** R2.3 - Validate Requests for Interchange (RFI) section is missing the Energy Product validation used to determine if additional reserves are needed and is a valid reason to deny a tag. **Such validation is not currently part of the required validation of an RFI. However, it may be part of the commercial evaluation of an RFI that may result in its denial.**

Organization	Yes or No	Question 4 Comment
		R2.4 - “Validate request to modify Interchange” is silent on the entities that have the rights/requirements for approval or denial. Curtailments should only require Source and Sink to approve that type of modification. Does “modify” really mean a market and/or reliability adjust? If so there needs to be a change to the terminology. **The information described is addressed in INT-006.** R2.5 - Should indicate which entities are distributed the RFI. **The information described is addressed in INT-006.** R2.6 - Should indicate which entities are distributed the RFI. **The information described is addressed in INT-006.**
Response:		
Duke Energy	Disagree	We agree that the lists of tasks are appropriate and sufficient to arrange interchange. However requirements to have “capabilities” should be certification requirements and do not belong in a Reliability Standard. This standard should be eliminated.
Response: These concepts are now included in the Guidelines and Technical basis section of INT-006 rather than in requirements of a standard.		
ISO New Enlgand Inc.	Disagree	We agree with the concept of including the required tasks in the standards; and with the current layout of the other standards putting them all within INT-011 is a reasonable approach. However, the phrase “that desires to” is not measureable and should be removed.
Response: To address your concern, the SDT has modified the requirement to apply to entities that “submit,” rather than “desire to submit.”		
WECC	Disagree	WECC does not have a comment on the tasks performed by the BAs, PSEs and TSPs. However, this standard lists the Reliability Coordinator in the Applicability section but there are no tasks, requirements or measures in the standard applicable to the RC. The RC should be removed from the applicable entity list. Furthermore, compliance measures and compliance monitoring information need to be identified in order for

Organization	Yes or No	Question 4 Comment
		functional entities to fully understand what they will be responsible for and comment accordingly.
Response: These concepts are now included in the Guidelines and Technical basis section of INT-006 rather than in requirements of a standard.		
SERC OC Standards Review Group	Disagree	While the SERC OC Standards Review Group agrees that this list of tasks is appropriate and sufficient to arrange interchange, we believe requirements to have “capabilities” more properly belong in certification and this standard should be eliminated. Currently, only Reliability Coordinators (RCs), Balancing Authorities (BAs) and Transmission Operators (TOPs) must be certified. We recognize that eliminating this standard may require additional entities to be certified
Response: These concepts are now included in the Guidelines and Technical basis section of INT-006 rather than in requirements of a standard..		

5. In the past, the industry has expressed concerns regarding how to manage Interchange transactions in the event of cyber attack or other incident. In response, the CI SDT has proposed that several requirements in INT-004-3, INT-006-3 and INT-011-1 be footnoted with the following "In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred."

In other cases, such as INT-009-2, this language was not included, indicating that at all times, regardless of tool availability, entities are expected to ensure that Interchange is coordinated, agreed to, and implemented as agreed.

Do you agree that this phrase and its selective use appropriately addresses concerns with managing Interchange transactions in the event of cyber attack or other incident? If no, please propose alternate language or a different approach.

Summary Consideration: The majority of respondents disagreed with this approach. Many objected to the use of footnotes to capture the proposed exception to the requirements. In response, the SDT has modified its approach to recommend the creation and planned implementation of a backup plan in the Guidelines and Technical basis section of INT-006. Also, the concerns with the timing of interchange distribution in INT-006 have been addressed by wording the requirement such that there is no violation due to distribution timing unless that timing violation created a reliability concern. .

Organization	Yes or No	Question 5 Comment
Ameren		
Central Lincoln		
South Carolina Electric and Gas		
American Electric Power (AEP)	Agree	
Bonneville Power Administration	Agree	
Duke Energy	Agree	

Organization	Yes or No	Question 5 Comment
Independent Electricity System Operator	Agree	
Manitoba Hydro	Agree	
Midwest ISO	Agree	
Midwest ISO Stakeholder Standards Collaborators	Agree	
NERC Staff	Agree	
MRO NERC Standards Review Subcommittee	Agree	
PacifiCorp	Agree	
Southern California Edison Co.	Agree	
California ISO	Disagree	
Functional Model Working Group		
Northeast Power Coordinating Council	Disagree	All transactions must be agreed to under any situations to ensure reliability. The proposed footnote and the added phrase appear to be adequate. No one should be found non-compliant if the hardware/software is not available to support these tasks, but we are not sure that these footnotes are the best way to achieve that goal. Can statements be made in the Measures and Compliance to address this?
Response: The SDT agrees that the neighboring BAs must have agreement on interchange regardless of whether the hardware/software is available. The change to the requirements associated with the distribution times in INT-006 alleviated the need for the language provided previously in the footnotes. .		
Entergy	Disagree	Entergy believes that this type of language is necessary to ensure compliance is not strictly enforced in situations where non-compliance is unintentional. However, we do not think that NERC's enforcement of these standards will be influenced by footnotes, so we would propose that this language is more directly

Organization	Yes or No	Question 5 Comment
		incorporated into the INT standards where appropriate.
Response: The change to the requirements associated with the distribution times in INT-006 alleviated the need for the language provided previously in the footnotes.		
PPL Energy Plus	Disagree	Footnotes 1&2 in INT-004-3 relieve all parties from the responsibility of assuring interchange takes place on the electric grid under poorly-defined circumstances. PPL believes removing responsibility for interchange under any circumstances places the reliability of the grid at great risk should critical software or hardware fail . A FAX, phone or other backup should be required to effect performance and this footnote should be deleted. This same footnote appears in the following standards and should be removed from all:ï• ¶ INT-006-4 Footnotes 2, 3, 5, 7, 8, 9, &10ï• ¶ INT-010-2 Footnotes 1, 2 & 3ï• ¶ INT-011-1 Footnotes 1, 2 & 3
Response: The SDT agrees that the neighboring BAs must have agreement on interchange regardless of whether the hardware/software is available. The change to the requirements associated with the distribution times in INT-006 alleviated the need for the language provided previously in the footnotes.		
Platte River Power Authority	Disagree	If tools are unavailable due to a cyber attack or other incident, an entity such as the Reliability Coordinator should declare an emergency and have the authority to suspend interchange coordination or implement a procedure for manual interchange coordination. It should not be left to the Compliance Monitor's discretion on a case by case basis to determine whether or not a violation of this requirement occurred.
Response: This capability already exists under existing standards. This standard does not prohibit the RC from taking such actions.		
Xcel Energy	Disagree	It is unclear as to whether an entity must still self report in cases where Interchange Coordination is nonfunctional. Do you have a statistic as to how often this occurs? So, if OATI goes down for an hour, must all EI entities self-report?
Response: The SDT agrees that the neighboring BAs must have agreement on interchange regardless of whether the hardware/software is available. The change to the requirements associated with the distribution times in INT-006 alleviated the need for the language provided previously in the footnotes. We believe this will address this concern.		
FirstEnergy	Disagree	It seems the drafting team's statement, "In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise

Organization	Yes or No	Question 5 Comment
		discretion in determining whether or not a violation of this requirement has occurred." assigns a compliance auditor an authority that they already have. This statement seems unnecessary. As an alternative the drafting team should require an entity to document and implement a manual process when the electronic capability (tool) is unavailable. Furthermore, in those extreme circumstances, the Standards of Conduct and Market Activity will be suspended and interchange activity will by necessity be managed by the BAs and TOPs.
Response: The SDT agrees that the Compliance Enforcement Authority already has this capability. The change to the requirements associated with the distribution times in INT-006 alleviated the need for the language provided previously in the footnotes.		
NorthWestern Energy	Disagree	No registered entity should be held responsible for any incident outside its control.
Response: The SDT concurs, and the change to the requirements associated with the distribution times in INT-006 alleviated the need for the language provided previously in the footnotes.		
PJM	Disagree	No, the phrase does not help. The phrase "where Interchange Coordination is non-functional" seems to really mean "when the Interconnection wide tool isn't operating". If the tool isn't working then the sink BAs must do that checkout without the tool. But the checkout must be done, otherwise all RFI will / must be rejected because there will be no validation that everyone has agree to the proposed RFIs. Compliance monitors are not reliability entities. They are more likely to get around to investigating an event at the end of a month then they are to helping a real time concern. The footnote does not add anything to the standard. Compliance Monitors have always had discretionary options. Transaction information must be agreed to "in all cases". Without agreement BAs will be at risk of raising generation while another BA is dropping load. The only reasonable alternative is only to make changes that have been confirmed (with or without OATI)
Response **The SDT agrees that the Compliance Enforcement Authority already has this capability. The SDT agrees that the neighboring BAs must have agreement on interchange regardless of whether the hardware/software is available. The change to the requirements associated with the distribution times in INT-006 alleviated the need for the language provided previously in the footnotes.**		
Nebraska Public Power District	Disagree	The standard should outline the funtional requirements (redudancy in communications, servers, etc.) for the design of the tool. If the tool is meets design requirements, there should not be a standard violation if there are elements outside of the entities control that hamper the ability to respond to respond in the event of failure of the internet. Leaving the decision to the discretion of the auditor is ambiguous and inconsistent and places

Organization	Yes or No	Question 5 Comment
		all risk on the entity involved on issues beyond the entity's control. This is not acceptable.
Response: The SDT does not believe it is appropriate to specify such technical details related to communications and redundancy in a reliability standard for Interchange.		
San Diego Gas & Electric	Disagree	There appears to be no clear reason as to why the footnoted phrase applies to similar requirements in one standard and not another. Therefore, the phrase should apply to similar requirements in all of the INT standards.
Response: The SDT has modified the requirements associated with the distribution times in INT-006, which alleviates the need for the language provided previously in the footnotes.		
ISO New Enlgand Inc.	Disagree	We agree that no one should be found non-compliant if the hardware/software is not available to support these tasks, but we are not sure that these footnotes are the best way to achieve that goal. Can statements be made in the measures and compliance to address this rather than a footnote?
Response: The SDT has modified the requirements associated with the distribution times in INT-006, which alleviates the need for the language provided previously in the footnotes		
SERC OC Standards Review Group	Disagree	We agree with the intent of the language and the standards to which it is applied, but it needs to be explicitly in the requirements. Footnotes are not requirements.
Response: The SDT has modified the requirements associated with the distribution times in INT-006, which alleviates the need for the language provided previously in the footnotes		
GSOC & GTC Response	Disagree	We understand the intent here but believe that the footnote language should be moved into the requirements to make them part of the standard. Requirements and measurements should not be listed in footnotes.
Response: The SDT has modified the requirements associated with the distribution times in INT-006, which alleviates the need for the language provided previously in the footnotes		

Organization	Yes or No	Question 5 Comment
WECC	Disagree	WECC agrees with the general concept that such events should be considered as special cases in the INT standards. However, performance metrics should be associated with all of the requirements in the INT standards so compliance and the functional entity clearly understand their obligations. Specifically, with respect to degradation due to coincidental, accidental or malicious causes, a specific measure, such as a system availability threshold, should be identified.
Response: The SDT has modified the requirements associated with the distribution times in INT-006, which alleviates the need for the language provided previously in the footnotes. It should be noted that NAESB currently has business practices that specify performance metrics in this area.		

6. INT-001-2 R2 requires:

R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:

R2.1. If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.

R2.2. For each bilateral Inadvertent Interchange payback.

The CI SDT believes that this is no longer required. Since the proposed INT-009-2 R2 makes is clear that the Net Scheduled Interchange term in the control equation can only include Confirmed Interchange as agreed to between Balancing Authorities and metered values for Dynamic Schedules, this by definition requires that an Arranged Interchange be created in order to implement the schedules listed in R2.1 and R2.2. From a reliability perspective, it is unimportant who creates these Arranged interchanges – only that they be created and confirmed prior to being entered into the control equation.

Do you agree that INT-001-2 R2 is no longer required, and does not need to be retained? If no, please explain why you believe the requirement is still needed.

Summary Consideration: The majority of commenters agreed this requirement could be eliminated.

Some commenters suggested that the standards should address Inadvertent Interchange. The SDT responded that Inadvertent Interchange is outside the scope of the standard.

Organization	Yes or No	Question 6 Comment
Ameren		
Central Lincoln		
San Diego Gas & Electric		
South Carolina Electric and Gas		
Bonneville Power Administration	Agree	
California ISO	Agree	

Organization	Yes or No	Question 6 Comment
Duke Energy	Agree	
Entergy	Agree	
FirstEnergy	Agree	
GSOC & GTC Response	Agree	
Manitoba Hydro	Agree	
Midwest ISO	Agree	
Midwest ISO Stakeholder Standards Collaborators	Agree	
NERC Staff	Agree	
MRO NERC Standards Review Subcommittee	Agree	
NorthWestern Energy	Agree	
PacifiCorp	Agree	
Platte River Power Authority	Agree	
SERC OC Standards Review Group	Agree	
Southern California Edison Co.	Agree	
WECC	Agree	
Functional Model Working Group		
Nebraska Public Power District	Agree	Although I agree the requirement can be retired, there is some question about the statement metered values

Organization	Yes or No	Question 6 Comment
		for Dynamic Schedules. Not all Dynamic Schedules are metered (with traditional metering equipment). There needs to be a mechanism to document the final hourly interchange, but it is not necessarily a meter for Dynamic Schedules
Response: The SDT has modified the standard to refer to the need for Dynamic Schedule values to come from an agreed on common source (not necessarily metered).		
Xcel Energy	Agree	However, INT-009 R2 has “or alternate control process” in parentheses. Believe this should be deleted. ACE is a measurement for compliance that may be used for control purposes. It is up to the entity to comply with the remaining NERC standards, including performance. The entity may be able to accomplish that without incorporating the NSI into their control process. The requirement should only state that the term be used in the BA’s ACE, though this may be unnecessary as ACE is defined in other standards.
Response: The SDT agrees that entities may not necessarily use ACE for control; however, we do not agree that accurate control can be accomplished without having NSI as an input into that control process. We do not presume to specify any other aspects of the control equation, but to not include NSI in the control equation would indicate that entities are not controlling to schedule, which is what this requirement intends to prohibit.		
PJM	Agree	The currently approved INT-001, as written, establishes responsibilities. PJM agrees that the elimination of this standard will not cause a problem for the simple reason that every other requirement establishes a responsible entity for the given task defined in the respective requirement. If done correctly the SDT only needs a requirement that Confirmed Interchange be transitioned to Implemented Interchange. There is no need to carve a special condition for Dynamic Schedules. If the Dynamic Schedule represents a point-to-point transaction it still requires that all parties agree with the terms of the transaction.
Response: The SDT believes that there are some special conditions related to Dynamic Schedules that must be explicitly identified, and has done so in INT-004.		
Northeast Power Coordinating Council	Disagree	The mandate in the original set of standards has been missed. INT-001 establishes the mandate that special case interchange be explicitly assigned to some entity. In the case of Inadvertent Interchange payback, such payback can be initiated by either BA that has an accumulation, but R2.2 clearly mandates that the responsibility falls on the sink BA. The SDT should raise the issue of whether or not Inadvertent Interchange is a reliability issue or a business issue. Where INT-001 relates to a single Interchange, INT-009 relates the sum of all Confirmed Interchange and to the fact that the net of Confirmed Interchange only goes into the ACE equation. These are two distinct functions. INT-009 recognizes that NET Interchange is done among adjacent BAs. INT-001 assigns responsibility to BAs that may or may not be adjacent.
Response: While the SDT agrees that INT-001 addresses individual interchange transactions and INT-009 addresses net interchange, the SDT believes		

Organization	Yes or No	Question 6 Comment
that INT-009 effectively enforces the provisions of INT-001 R2, making R2 superfluous. The SDT does not believe it is a reliability issue as to what entity enters the net interchange identified in INT-001 R2.2. If an entity wishes to implement Interchange, it has no choice but to create an interchange transaction to do so, as that is the only manner in which INT-009 allows the implementation of Interchange. **This project does not address Inadvertent Interchange, except to the extent that payback is accomplished bilaterally through Interchange (in which case, it is treated the same as any other Interchange).**		
Independent Electricity System Operator	Disagree	The SDT seems to have missed the distinction made in the original set of standards. INT-001 establishes the mandate that special case interchange be explicitly assigned to some entity. In the case of Inadvertent Interchange payback, such payback can be initiated by either BA that has an accumulation, but R2.2 clearly mandates that the responsibility falls on the sink BA. The SDT would be better served to raise the issue of whether or not Inadvertent Interchange is a reliability issue or a business issue. Where INT-001 relates to a single Interchange, INT-009 relates the sum of all Confirmed Interchange and to the fact that the net of Confirmed Interchange only goes into the ACE equation. These are two distinct functions. INT-009 recognizes that NET Interchange is done among adjacent BAs. INT-001 assigns responsibility to BAs that may or may not be adjacent.
Response: While the SDT agrees that INT-001 addresses individual interchange transactions and INT-009 addresses net interchange, the SDT believes that INT-009 effectively enforces the provisions of INT-001 R2, making R2 superfluous. The SDT does not believe it is a reliability issue as to what entity enters the net interchange identified in INT-001 R2.2. If an entity wishes to implement Interchange, it has no choice but to create an interchange transaction to do so, as that is the only manner in which INT-009 allows the implementation of Interchange. **This project does not address Inadvertent Interchange, except to the extent that payback is accomplished bilaterally through Interchange (in which case, it is treated the same as any other Interchange).**		
ISO New Enlgand Inc.	Disagree	The SDT seems to have missed the distinction made in the original set of standards. INT-001 establishes the mandate that special case interchange be explicitly assigned to some entity. In the case of Inadvertent Interchange payback, such payback can be initiated by either BA that has an accumulation, but R2.2 clearly mandates that the responsibility falls on the sink BA. The SDT would be better served to raise the issue of whether or not Inadvertent Interchange is a reliability issue or a business issue. Where INT-001 relates to a single Interchange, INT-009 relates the sum of all Confirmed Interchange and to the fact that the net of Conformed Interchange only goes into the ACE equation. These are two distinct functions. INT-009 recognizes that NET Interchange is done among adjacent BAs. INT-001 assigns responsibility to BAs that may or may not be adjacent.
Response: While the SDT agrees that INT-001 addresses individual interchange transactions and INT-009 addresses net interchange, the SDT believes that INT-009 effectively enforces the provisions of INT-001 R2, making R2 superfluous. The SDT does not believe it is a reliability issue as to what entity enters the net interchange identified in INT-001 R2.2. If an entity wishes to implement Interchange, it has no choice but to create an interchange transaction to do so, as that is the only manner in which INT-009 allows the implementation of Interchange.		

Organization	Yes or No	Question 6 Comment
This project does not address Inadvertent Interchange, except to the extent that payback is accomplished bilaterally through Interchange (in which case, it is treated the same as any other Interchange).		
PPL Energy Plus	Disagree	Unless dynamic schedules are tagged and identified in the Coordinated Interchange software that is used to develop the net schedule, they will never be curtailed using same software. This means all other schedules have a lower priority than Dynamic schedules and this should not be the case. We are not convinced that INT-009-2 R2 adequately conveys the requirement that dynamic schedules be tagged and tracked in curtailment software. Further, under R2.2: the word “Plus” is used to describe inclusion of a number (the Dynamic schedule) which may or may not be POSITIVE. It may be best to use a word other than “Plus” such as “including” or “summation” in order to provide clarification and accuracy.
Response: If an entity wishes to schedule Interchange (via a Dynamic Schedule or otherwise), it has no choice but to create an interchange transaction to do so, as that is the only manner in which INT-009 allows the implementation of scheduled Interchange. However, the team is aware that this does not address the case of Pseudo-ties. The SDT plans to address Pseudo-ties in the next version of the standard. **The SDT has eliminated the use of the word “plus.”**		
American Electric Power (AEP)	Agree	We agree that it is unimportant who creates the Arranged Interchange. Confirmation by all affected applicable and reliability entities are what are ultimately important.
Response: Thank you for your supportive comment.		

7. INT—004-2 R1 requires:

R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.

The CI SDT believes that at a minimum, this requirement does not belong in the "Dynamic Schedules" standard. However, for several reasons, the CI SDT further believes that this specific requirement is no longer required:

- It mandates a practice (releasing of E-Tag limits) that is more process related
- The practice is already addressed in related NAESB standards (WEQ-004 Appendix B - E-Tag Actions[2])
- Use of a limit (and the associated release of that limit) is only one particular way to address curtailments. Other ways exist that could be used in lieu of this approach. The reliability standard should not mandate a single approach when others may suffice.

Do you agree INT-004-2 R1 can be eliminated? If no, please explain why the requirement is still needed.

Summary Consideration: The majority of commenters agreed this requirement could be eliminated.

Organization	Yes or No	Question 7 Comment
Ameren		
Central Lincoln		
San Diego Gas & Electric		
South Carolina Electric and Gas		
Bonneville Power Administration	Agree	
California ISO	Agree	

[2] Commenters that wish to gain access to review NAESB WEQ-004 should contact NAESB at www.naesb.org and request information regarding the options available for acquiring access to NAESB standards.

Organization	Yes or No	Question 7 Comment
Duke Energy	Agree	
Entergy	Agree	
FirstEnergy	Agree	
Functional Model Working Group		
GSOC & GTC Response	Agree	
Independent Electricity System Operator	Agree	
ISO New Enlgand Inc.	Agree	
Manitoba Hydro	Agree	
Midwest ISO	Agree	
Nebraska Public Power District	Agree	
NERC Staff	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Northeast Power Coordinating Council	Agree	
NorthWestern Energy	Agree	
PacifiCorp	Agree	
PJM	Agree	
Platte River Power Authority	Agree	

Organization	Yes or No	Question 7 Comment
SERC OC Standards Review Group	Agree	
Southern California Edison Co.	Agree	
WECC	Agree	
Xcel Energy	Agree	
PPL Energy Plus	Disagree	**Please re-insert R2 from INT-004-2 that requires a release and reload of interchange that has been curtailed. Please assure that in all cases, the PSE's are kept informed of all curtailments and reloads. **The SDT has modified the requirements to include PSEs.** **R1: Loads with dynamic schedules are still the responsibility of the Sink BA who should be included as a responsible party. The old requirement that Sink BA's arrange for dynamic schedules for Joint Owned Units (JOUs) and inadvertent payback is implied, but not stated. Please clearly state that the entity responsible for Arranging Dynamic Interchange for JOUs and inadvertent payback is the Sink BA in the new standards. **The SDT does not believe there is a reliability reason that Sink BA's be required to arrange dynamic schedules for JOUs and Inadvertent Payback.** **R2.3 requires the PSE to modify the dynamic schedule for reliability concerns communicated by the RC/TOP to the PSE's. However, it does not appear that these INT standards require the RC/TOP to notify the PSE that a reliability concern exists and that the associated modification(s) or reload(s) must take place. Please insert such notification to the affected PSE(s) into the requirement. **The SDT has changed the requirement to indicate that PSEs must make changes only if the receive notification of the need for such changes.**
Response:		
Midwest ISO Stakeholder Standards Collaborators	Agree	Reloading of transactions does not support reliability but rather supports continuance of commercial activity once the reliability event is over. Thus, reloading of transactions does not belong in reliability standards. It would be an issue better dealt with by NAESB.
Response: Thank you for your supportive comment.		
American Electric Power (AEP)	Disagree	This should pertain to all impacted Interchange Schedules, where the releasing entity should electronically notify release of reliability profile curtailment. Verbally, as a backup, if the electronic process has failed to

Organization	Yes or No	Question 7 Comment
		ensure Sink BA ultimately as needed.

Response: The SDT does not believe any reliability reason to support the notification has been provided.

8. Requirements R1 and R7 in INT-006-4 have been created to address earlier requirements related to the distribution of Interchange information within one minute of a specific action. This one minute limit seemed in most cases to have little or no impact on reliability. The CI SDT discussed this issue at length, and attempted to determine a way in which the one minute requirement only would apply only if its exceedence resulted in a case where the ability to schedule the transaction reliably could have been hindered by the delay. To do this, the CI SDT created several criteria which must be met to constitute a violation:

R1. Each Sink Balancing Authority shall distribute all Arranged Interchange to the Source Balancing Authority, each Intermediate Balancing Authority, each Reliability Coordinator, and each Transmission Service Provider included in the Arranged Interchange less than one minute after receipt of any associated Request for Interchange or requested modifications to Confirmed or Implemented Interchange that meets all of the following criteria:

1.1. The Request for Interchange or requested modification to Confirmed or Implemented Interchange was received by the Sink Balancing Authority on-time, and

1.2. The Arranged Interchange was not transitioned to Confirmed Interchange, and

1.3. Notification of the Arranged Interchange being transitioned to Confirmed Interchange was distributed less than three minutes prior to the requested ramp start, and

1.4. The Arranged Interchange was not denied by any approval entity.

R7. Each Sink Balancing Authority shall distribute all notifications of whether or not Arranged Interchange was transitioned to Confirmed Interchange to the Source Balancing Authority, each Intermediate Balancing Authority, each Reliability Coordinator, and each Transmission Service Provider included in the Arranged Interchange less than one minute after making the decision to transition or not for any Arranged Interchange that meets all of the following criteria:

7.1. The Request for Interchange or requested modification to Confirmed or Implemented Interchange was received by the Sink Balancing Authority on-time, and

7.2. Notification of whether or not the Arranged Interchange was transitioned to Confirmed Interchange was not distributed three or more minutes prior to the requested ramp start, and

7.3. Not all entities actively responded during the reliability assessment period defined in the timing requirements in Attachment 1, column B, and

7.4. The Arranged Interchange was not denied by any approval entity.

Do you agree with this approach? If no, what do you believe the correct approach should be?

Summary Consideration: There was no clear consensus regarding these requirements. The team has proposed alternate language to simplify the standard, while retaining the allowance for exceedances of the times identified in Attachment 1, provided they do not result in poor reliability outcomes.

Organization	Yes or No	Question 8 Comment

Organization	Yes or No	Question 8 Comment
Ameren		
Central Lincoln		
San Diego Gas & Electric		
South Carolina Electric and Gas		
California ISO	Agree	
Duke Energy	Agree	
Manitoba Hydro	Agree	
Midwest ISO	Agree	
Midwest ISO Stakeholder Standards Collaborators	Agree	
MRO NERC Standards Review Subcommittee	Agree	
PacifiCorp	Agree	
Platte River Power Authority	Agree	
Southern California Edison Co.	Agree	
Functional Model Working Group		
PPL Energy Plus	Disagree	**R1: The reasoning behind R1.3 (less than the three-minute time) is not clear. In fact, R1.2 and R1.3 seem to be at odds with one another. Would the CI SDT please review the concepts under R1 and clarify the wording of sub-requirements 1.2 and 1.3? **The SDT has simplified R1 to address this concern.** **R3.1 Item 1): Should "remaining for the TSR" be "remaining on the TSR"?

Organization	Yes or No	Question 8 Comment
		The SDT has modified the requirement to align with the suggestion. **R3.1 Item 3): This requirement needs to allow for situations where the physical transmission path is intact, but a software tool does not have the right database model. In this case, a responsible entity should be allowed the discretion to allow the Interchange to flow regardless of the underlying software model. **The standard does not mandate the use of or adherence to any software model. To the extent an operator knows that the path is valid, it should approve the Arranged Interchange, regardless of what any model indicates.** **R6: Sub-requirements 6.1 through 6.3 include a logical "and". Should this be a logical "or"? **By specifying that the action shall not take place if "any" of conditions 6.1 though 6.3 are met, the logical operator is an "OR."** **R7: The PSE (or other party originating Arranged Interchange) should be included in the list of parties notified of transition from Arranged to Confirmed. Please correct this omission. **The SDT has addressed this issue as suggested.**
Response:		
Nebraska Public Power District	Agree	Although we agree with the philosophy of the SDT to limit the one minute requirement for distributing Interchange information to only those cases that impact reliability, the requirements are anything but straightforward. Without the explanation at the beginning of the question, it would be very difficult to determine the intent. There should be a simpler way to implement the intent of the SDT.
Response: The SDT has simplified R1 to address this concern.		
Entergy	Disagree	Entergy believes Requirements R1 and R7 as written are overly complex. Also, this standard seems to complicate interchange coordination without improving reliability.
Response: The SDT has simplified R1 & R7 to address this concern to only result in a standard violation if there are reliability impacts associated with not meeting the timing table specifications.		
Northeast Power Coordinating Council	Disagree	INT-006 was designed to mandate the distribution of information. There is a possibility that an IA could collect approvals/denials and not inform anyone of the results. Hence there is a need to mandate that the data be distributed. If one agrees that the data be distributed, one could argue that there is a need to define

Organization	Yes or No	Question 8 Comment
		the time-frame. The NAESB Tables bind the analysis and response times. The Timing Tables in INT-006-3 create a window of 1 minute between when confirmations are mandated and when they are implemented. Given the fact that it takes some time to change the values going into a BA's ACE equation there is not a lot of time to allocate. The one-minute period is consistent with the Tables. With respect to the specific requirements of R1, we agree with R1.1, but do not understand how R1.2, R1.3 and R1.4 apply to the general statement in R1 that addresses distributing 'a request' within a minute of its receipt. For example, if the request has not yet been distributed - how can it have been denied (R1.4)? **The SDT has simplified R1 to address this concern to only result in a standard violation if there are reliability impacts associated with not meeting the timing table specifications.** We do not agree with R7.2, 7.3, 7.4. The general text of R7 is to requiring notification of whether or not AI was transitioned to Confirmed. The language of R7.2 implies something has already been distributed, yet the purpose of R7 is the actual distribution. If 7.3 or 7.4 are true the notification should be that is WAS NOT transitioned to Confirmed. If the intent is to only require notification of AI that was Confirmed, then the language of R7 needs to be modified to reflect that intent. **The SDT has simplified R7 to address this concern to only result in a standard violation if there are reliability impacts associated with not meeting the timing table specifications.**
Response:		
PJM	Disagree	PJM is satisfied that the reliability conditions are established and ensured by INT-003-2. The current and the proposed INT-006 impose subjective, unmeasureable procedureal mandates (e.g. the BA shall evaluate a schedule with respect to....) There are no measures associated with the current standard. PJM could support deleteing INT-006. The proposed INT-006 does correct the subjectivity of the old INT-006, but does so at the expense of imposing administrative guidelines that could, under emergency conditions, divert a system operator attention to focusing on RFI at the expense of evaluating system conditions.
Response: The SDT agrees there are no measures currently in the standard, and will be developing them in a future draft. **The SDT is uncertain how a system operator would be diverted from evaluating system conditions by this standard.**		
NorthWestern Energy	Disagree	R1.R1 requires that the Sink Balancing Authority distribute each Arranged Interchange to the various entities specified in the Requirement "less than one minute after receipt of any Request for Interchange..." NorthWestern is very concerned by this requirement and strongly believes that a Balancing Authority should not be held responsible for timing that is at the mercy of the software provider, Internet traffic, etc. The time to act on a Request for Interchange can and must be managed by the Balancing Authority personnel, but placing the distribution time requirement on the Balancing Authority is unfair and misdirected.

Organization	Yes or No	Question 8 Comment
		The Standard does not mandate the use of any particular software or communication methodology, simply the performance objectives of the responsible entity. It is up to the entity to determine how best to meet those performance objectives. The timing tables have been modified to provide more than one minute for Interchange that have start times further in the future. In addition, the proposed requirement only results in a standard violation of there are reliability impacts associated with not meeting the timing table specifications. R4.It is unclear what "associated with a direct-current tie operator" means in the context of the Requirement. Does this mean that a Balancing Authority that is a direct-current tie operator must follow the requirement, or any Balancing Authority that receives a Request for Interchange that includes a direct-current tie operator as a party to the Request for Interchange? **The SDT has clarified the language by reordering the entities.** R7.The concern described for R1 also applies to the one minute notification timing requirement included within R7. **The Standard does not mandate the use of any particular software or communication methodology, simply the performance objectives of the responsible entity. It is up to the entity to determine how best to meet those performance objectives. The timing tables have been modified to provide more than one minute for Interchange that have start times further in the future. In addition, the proposed requirement only results in a standard violation of there are reliability impacts associated with not meeting the timing table specifications.**
Response:		
GSOC & GTC Response	Disagree	Remove these requirements completely.
Response: The SDT does not understand the justification for the suggested removal.		
NERC Staff	Disagree	The level of detail in these requirements seems intended to codify the behavior of software tools currently in use. While we believe there is value in the industry agreeing on a common set of tools and practices related to Interchange coordination, we question if they should be required in a reliability standard and monitored for compliance.
Response: The SDT has simplified R1 & R7 to address this concern to only result in a standard violation of there are reliability impacts associated with not meeting the timing table specifications.		

Organization	Yes or No	Question 8 Comment
FirstEnergy	Disagree	The one minute time limit appears to have sprung from the e-tag system specifications document and was related to ensuring market activity was unimpeded (i.e. first request through the door was the first request considered for implementation). The speed with which these transactions are managed is a market issue. The requirement should be to implement the schedule as approved. R1 and R7 may be difficult to measure and prove compliance during times of system failures. In R1.1 and R7.1 it is not clear what constitutes "on time."
Response: The SDT has simplified R1 & R7 to address this concern to only result in a standard violation of there are reliability impacts associated with not meeting the timing table specifications. The classification of “On time” is specified in the timing tables.		
SERC OC Standards Review Group	Disagree	The SERC OC Standards Review Group cannot determine a reliability reason to have either R1 or R7. Further, we believe Requirements R1 and R7 as written are unclear, unmeasureable, and unenforceable.
Response: The SDT has simplified R1 & R7 to address this concern to only result in a standard violation if there are reliability impacts associated with not meeting the timing table specifications.		
Xcel Energy	Disagree	This is predicated on an electronic platform. What occurs if the electronic platform is not available? Is a manual process taken into account? If a manual process had to be implemented, the 1 minute time frame would not be reasonable.
Response: The SDT has modified the language to be clearer when and how the requirement should apply.		
Bonneville Power Administration	Agree	We agree with the approach. However, how does the Sink Balancing Authority demonstrate compliance with the less than one minute distribution requirement? Will each tagging software vendor provide a check that records or logs the demonstration of each distribution’s meeting the 1-minute-or-less threshold? We believe the data is logged today. We’re not certain that a check is made to ensure distribution occurs within a minute or less timeframe as well as documented evidence of such.
Response: The use of such logs would likely be acceptable. This information will be discussed further as measures are developed.		
Independent Electricity System Operator	Agree	We agree with the general approach of INT-006. With respect to the specific requirements of R1, we agree with R1.1, but we do not understand how R1.2, R1.3 and R1.4 apply to the general statement in R1 that is talking about distributing ‘a request’ within a minute of its receipt. For example, if the request has not yet been distributed - how can it have been denied (R1.4).We do not agree with R7.2, 7.3, 7.4. The general text of R7 is to require notification of ‘whether or not AI was transitioned to Confirmed. The language of R7.2 implies something has already been distributed, yet the purpose of R7 is the actual distribution. If 7.3 or 7.4 are true the notification should be that it WAS NOT transitioned to Confirmed. If the intent is to only require notification of AI that was confirmed, then the language of R7 needs to be modified to reflect that intent.INT-

Organization	Yes or No	Question 8 Comment
		006 was designed to mandate the distribution of information. **The SDT has simplified R1 & R7 to address this concern to only result in a standard violation if there are reliability impacts associated with not meeting the timing table specifications.** One could argue that there is a possibility that an IA would collect approvals/denials and not inform anyone of the results, and hence there is a need to mandate that the data be distributed. If one agrees that the data be distributed, one could argue that there is a need to define the time-frame. The NAESB Tables bound the analysis and response times. The Timing Tables in INT-006-3 create a window of 1 minute between when confirmations are mandated and when they are implemented. Given the fact that it takes some time to change the values going into a BA's ACE equation there is not a lot of time to allocate. The one-minute period is consistent with the Tables. **The SDT has simplified R1 & R7 to address this concern to only result in a standard violation if there are reliability impacts associated with not meeting the timing table specifications.**
Response:		
American Electric Power (AEP)	Disagree	We do not agree that Sink BA should be responsible to distribute. This should be a function of IA or NERC.
Response: The SDT does not believe having a separately registered IA is practical or valuable, and the majority of responses to question 2 seem to agree. **In general, the SDT believes it is more appropriate for the industry to develop tools to comply with the standards, rather than for NERC to supply the tools. NERC's role in tools development should for the most part be a supporting one.**		
WECC	Disagree	WECC agrees with the concept but the language is wordy and difficult to follow. Specifically, the CI SDT should consider whether the "and" is appropriate in this context. For example, 1.2 and 1.3 appear contradictory - how can an Arranged Interchange not transition to Confirmed Interchange and still have notice of the Arranged Interchange being transitioned to Confirmed Interchange. Perhaps a flow chart would be easier to understand. Also, emergency transactions can be entered in real-time or after the fact and may need to be specifically addressed. This also needs to be clarified. In general, however, WECC agrees that as long as the transaction is delivered when it was scheduled there is not a reliability issue.
Response: The SDT has simplified R1 & R7 to address this concern to only result in a standard violation if there are reliability impacts associated with not meeting the timing table specifications.		

Organization	Yes or No	Question 8 Comment
ISO New Enlgand Inc.	Disagree	While we agree with the general approach of INT-006, we have the following comments/questions. With respect to the specific requirements of R1, we agree with R1.1, but we do not understand how R1.2, R1.3 and R1.4 apply to the general statement in R1 that is talking about distributing ‘a request’ within a minute of its receipt. For example, if the request has not yet been distributed - how can it have been denied (R1.4).We do not agree with R7.2, 7.3, 7.4. The general text of R7 is to requiring notification of ‘whether or not AI was transitioned to Confirmed. The language of R7.2 implies something has already been distributed, yet the purpose of R7 is the actual distribution. If 7.3 or 7.4 are true the notification should be that is WAS NOT transitioned to Confirmed. If the intent is to only require notification of AI that was Confirmed, then the language of R7 needs to be modified to reflect that intent.
Response: The SDT has simplified R1 & R7 to address this concern to only result in a standard violation if there are reliability impacts associated with not meeting the timing table specifications.		

9. Requirements R2.1 and R3.1 in INT-006-4 now list specific reasons for which a Balancing Authority or Transmission Provider, respectively, must deny an arranged Interchange:

2.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange if 1.) it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange, and/or 2.) the scheduling path (proper connectivity of Adjacent Balancing Authorities) is invalid.

3.1. Transmission Service Providers shall deny the Arranged Interchange if 1.) the unscheduled capacity remaining for the Transmission Service Request (or other contractual/tariff arrangement) on the Transmission Providers system will not accommodate the Arranged Interchange, 2.) the Transmission system does not have the capability to accommodate the Arranged Interchange based on projected system conditions, or 3.) the transmission path (proper connectivity of adjacent Transmission Service Providers) is invalid.

Do you agree that these reasons should be specified and that the reasons listed are appropriate? If no, please explain your answer.

Summary Consideration: There was no clear consensus regarding these requirements. Some entities pointed out that, as specified, the responsibility for verification of scheduling path and transmission path was not appropriately assigned; the SDT modified the requirements to address this deficiency. Other entities objected to the "pre-emptive" curtailments proposed for the Transmission Service Provider; that aspect of the requirement was removed.

Organization	Yes or No	Question 9 Comment
Ameren		
Central Lincoln		
San Diego Gas & Electric		
South Carolina Electric and Gas		
Manitoba Hydro	Agree	
NERC Staff	Agree	
NorthWestern Energy	Agree	

Organization	Yes or No	Question 9 Comment
PacifiCorp	Agree	
Platte River Power Authority	Agree	
Southern California Edison Co.	Agree	
PPL Energy Plus	Disagree	**R3.1 Item 1): Should "remaining for the TSR" be "remaining on the TSR"? **The SDT has modified the langue to address this concern.** **R3.1 Item 3): This requirement needs to allow for situations where the physical transmission path is intact, but a software tool does not have the right database model. In this case, a responsible entity should be allowed the discretion to allow the Interchange to flow regardless of the underlying software model. **The standard does not mandate the use of or adherence to any software model. To the extent an operator knows that the path is valid, it should approve the Arranged Interchange, regardless of what any model indicates.**
Response:		
Nebraska Public Power District	Disagree	Although the reasons should be specified, we do not agree that the Source and Sink Balancing Authority needs to know proper connectivity throughout the entire path. Intermediate Balancing Authorities should verify connectivity to adjacent Balancing Authorities. It is unrealistic for the Source or Sink Balancing Authority to know the connectivity of all the Balancing Authorities in North America.
Response: The SDT has modified the requirement to address this issue.		
California ISO	Agree	An RFI missing the valid product Energy Code is also a reason for denial.
Response: The requirement does not prohibit entities from denying for this reason.		
American Electric Power (AEP)	Disagree	Different Market models and structure, such as SPP, do not line up with the intent of what this Standard is trying to accomplish. While we agree with intent, concept and approach, they are not reflective of the different Market models currently in operation today.

Organization	Yes or No	Question 9 Comment
Response: The SDT is unaware of any particular conflicts with any market model. Note that the standard only specifies when you must deny, not that these are the only reasons for denial that are allowed. The SDT has added a footnote to the requirement to make this clear.		
Entergy	Disagree	Entergy agrees with the requirement tied to Balancing Authorities (R2.1). Entergy does not agree with the requirement for Transmission Service Providers (R3.1) to deny based on projected system conditions as TSPs. The role of the TSP is to model available transmission capability, while the role of the Transmission Operators is to perform security assessments of the operating timeframe. TOPs currently do not have a role in interchange assessment, so we believe that the requirement should be removed.
Response: The SDT has removed the language as suggested.		
Midwest ISO	Agree	Language should be added to define that the only responsibility to validate adjacency of a scheduling path (in 2.1) to a BAs own interconnection. Similarly, each TSP (in 3.1) will only be responsible to validate adjacency of a transmission path only to the extent of its interconnecting TSPs.
Response: The SDT has modified the requirements to make this clear.		
Midwest ISO Stakeholder Standards Collaborators	Agree	Language should be added to define that the only responsibility to validate adjacency of a scheduling path (in 2.1) to a BAs own interconnection. Similarly, each TSP (in 3.1) will only be responsible to validate adjacency of a transmission path only to the extent of its interconnecting TSPs.
Response: The SDT has modified the requirements to make this clear.		
MRO NERC Standards Review Subcommittee	Disagree	Language should be added to specify that the BA's only responsibility is to validate connectivity of the adjacent scheduled path (in 2.1) to a BAs own interconnection. Similarly, each TSP (in 3.1) will only be responsible to validate connectivity of the adjacent transmission path only to the extent of its interconnecting TSPs.
Response: The SDT has modified the requirements to make this clear.		
GSOC & GTC Response	Disagree	Postings and associated reservations made on OASIS are based on studies. The TLR process is defined for curtailments.
Response: The SDT believes the commenter is referring to the language related to pre-emptive curtailments, and has removed the language per the suggestion of another commenter.		
Functional Model Working Group		The reliability issue is whether or not the Interchange is approved or denied. The reasoning for that decision is

Organization	Yes or No	Question 9 Comment
		not a reliability issue as much as it is a business issue.
Response: The requirements are specifying the reliability reasons for which the Interchange *must* be denied. The SDT agrees there may be other reasons why a transaction may be denied. The SDT has added a language describing this in the Rationale for these requirements		
PJM	Disagree	The reliability issue is whether or not the Interchange is approved or denied. The reasoning for that decision is not a reliability issue as much as it is a business issue. The idea of listing the reasons for denial merely limits the BAs reliability options for denying a business request. Being too busy to evaluate a request is a legitmate reason for denying a request that may or may not be harmful to the system (i.e. the BA does not want to operate in an unexamined system state.)
Response: The requirements are specifying the reliability reasons for which the Interchange *must* be denied. The SDT agrees there may be other reasons why a transaction may be denied (although we do not necessarily agree that being too busy is one of them). The SDT has added language describing this in the Rationale for these requirements.		
Independent Electricity System Operator	Agree	The reliability reasons for denying an interchange request should be provided.
Response: Thank you for your supportive comment.		
Northeast Power Coordinating Council	Disagree	The reliability reasons for denying an interchange request should be provided. With respect to economic markets, the reasons listed are appropriate, but the timing of their applicability should be reconsidered. For example, each market has submittal deadlines. Until those submittal deadlines have been reached, the system conditions are not fully understood and no action can be taken to ‘deny’ a request. For example, if a new interchange request, Request A, would result in the flow on an interface to exceed the transfer capability - another interchange request, Request B, may be submitted that would net against Request A. There is no reliability issue that needs to be addressed until the market deadline has passed.
Response: The SDT believes the commenter is referring to the language related to pre-emptive curtailments, and has removed the language per the suggestion of another commenter.		
FirstEnergy	Disagree	This requirement appears to limit the "reliability reasons" for denying a transaction to only those listed. We seem again to be mixing business practices with reliability-related issues. In R3.1, the transmission path is contractual and may not accurately represent the actual flow; therefore, this may be a market issue and may not directly be a reliability issue.

Organization	Yes or No	Question 9 Comment
Response: The requirements are specifying the reliability reasons for which the Interchange *must* be denied. The SDT agrees there may be other reasons why a transaction may be denied. The SDT has added language describing this in the Rationale for these requirements. **The SDT believes the commenter is referring to the language related to pre-emptive curtailments, and has removed the language per the suggestion of another commenter.**		
ISO New Enlgand Inc.	Agree	We agree that the list of reasons for denial should be provided in the standard and are appropriate. However, with respect to economic markets, we believe the timing of the reviews should be reconsidered; or an exemption may be required for these timelines in areas with economic markets. For example, in economic markets with submittal deadlines, the system conditions for evaluation of the Arranged Interchange is not understood until those submittal deadlines have passed. Therefore, no action can be taken to 'deny' a request in the timeframes noted. For example, if a new interchange request, Request A, would result in the flow on an interface to exceed the transfer capability - another interchange request, Request B, may be submitted that would net against Request A. There is no reliability issue that needs to be addressed until the market deadline has passed.
Response: The SDT believes the commenter is referring to the language related to pre-emptive curtailments, and has removed the language per the suggestion of another commenter.		
Xcel Energy	Agree	We agree with specifying the minimum criteria for which AI can be denied; consider adding language similar to INT-010 R4.5 "Any real-time reliability concern related to a specific Arranged Interchange, provided that concern is supported by evidence."
Response: The requirements are specifying the reliability reasons for which the Interchange *must* be denied. The SDT agrees there may be other reasons why a transaction may be denied. The SDT has added language describing this in the Rationale for these requirements.		
Duke Energy	Agree	We agree, but believe that the language could be more clear that you are only responsible for validating paths relevant (i.e. adjacent) to your system.
Response: The SDT agrees, and has modified the standard to reflect this.		
Bonneville Power Administration	Disagree	We are struggling with how a Transmission Service Provider proves that it denied Arranged Interchange whenever its transmission system did not have the capability to accommodate Arranged Interchange based on "projected system conditions". The latter term is vague and seems difficult to validate that whenever such conditions occurred, the TSP responded with denial actions.
Response: The SDT believes the commenter is referring to the language related to pre-emptive curtailments, and has removed the language per the suggestion of another commenter.		

Organization	Yes or No	Question 9 Comment
WECC	Disagree	WECC does not have a comment on INT-006 base requirement R2. However, sub-requirement R2.1 is difficult to monitor for compliance. There is no way to measure or document whether a BA “expects” or “does not expect” to be capable of supporting the Interchange. Furthermore, R2.1 does not appear to enhance reliability. BAs have adequate authority to deny a tag for reliability and validity reasons without inclusion of this sub-requirement.
Response: The SDT believes the commenter is referring to the language related to pre-emptive curtailments, and has removed the language per the suggestion of another commenter. **The requirements are specifying the reliability reasons for which the Interchange *must* be denied. The SDT agrees there may be other reasons why a transaction may be denied. The SDT has added language describing this in the Rationale for these requirements.**		
SERC OC Standards Review Group	Disagree	While we agree with R2.1 and reasons 1 and 3 of R3.1, the TSP cannot know projected system conditions as suggested in reason 2 of R3.1. This amounts to a preemptive TLR before the real time flows materialize.
Response: The SDT believes the commenter is referring to the language related to pre-emptive curtailments, and has removed the language per the suggestion of another commenter.		

10. Requirement R4 in INT-006-4 now requires that Reliability Adjustment Requests for Interchange (i.e., curtailments) must be approved by each of the appropriate Balancing Authorities "if (the BA) can support the magnitude of the Interchange, including ramping, throughout the duration of the Reliability Adjustment Request for Interchange."

Do you agree that in the case of curtailment, a Balancing Authority must approve the curtailment unless the magnitude of Interchange, including ramping, cannot be supported? If no, what do you believe are valid reasons for denying a curtailment?

Summary Consideration: There was no clear consensus for this requirement. Some entities did not believe it appropriate to mandate an approval or denial without allowing for more flexibility; the requirement was modified to require they notify their RC if a Reliability Adjustment Arranged Interchange is denied.

Organization	Yes or No	Question 10 Comment
Ameren		
Central Lincoln		
PPL Energy Plus		
San Diego Gas & Electric		
South Carolina Electric and Gas		
Bonneville Power Administration	Agree	
California ISO	Agree	
Functional Model Working Group		
GSOC & GTC Response	Agree	
Independent Electricity System Operator	Agree	

Organization	Yes or No	Question 10 Comment
ISO New Enlgand Inc.	Agree	
Manitoba Hydro	Agree	
NERC Staff	Agree	
Northeast Power Coordinating Council	Agree	
Platte River Power Authority	Agree	
Southern California Edison Co.	Agree	
WECC	Agree	
PJM	Disagree	A NERC requirement should not impose an ad hoc approval or denial. Each request must be evaluated in the context of the system conditions at the time.
Response: The requirement was modified to require they notify their RC if a Reliability Adjustment Arranged Interchange is denied.		
Entergy	Disagree	Entergy believes that curtailments are real-time reliability actions, and denials impair the reliability of the BES. Therefore, the language “if (the BA) can support the magnitude of the Interchange” decreases the effectiveness of curtailments for resolving reliability problems. Instead of the Balancing Authority which requires relief receiving it, the other BA(s) associated with the curtailed transaction may deny based on the burden to their system(s). The requirement language also implies that the BA denying such a curtailment may be failing their reserve requirements since they are unable to allow the curtailment request.
Response: The requirement was modified to require they notify their RC if a Reliability Adjustment Arranged Interchange is denied		
PacifiCorp	Disagree	In cases of reliability adjustments (curtailments), PacifiCorp does not believe that there are any valid reasons for denying a curtailment.
Response: The requirement was modified to require they notify their RC if a Reliability Adjustment Arranged Interchange is denied.		
Midwest ISO	Disagree	Language should be changed to On-Time Reliability Adjustment Requests. "Late" (and even past-) requests MAY still be approved, but should not be a NERC defined "Must". E-Tag specifications may be changed to passively-APPROVE reliability adjustment requests to accommodate this standard, but that should only be

Organization	Yes or No	Question 10 Comment
		automatic if the request is On-Time.
Response: The requirement was modified to require they notify their RC if a Reliability Adjustment Arranged Interchange is denied.		
Midwest ISO Stakeholder Standards Collaborators	Disagree	Language should be changed to On-Time Reliability Adjustment Requests. "Late" (and even past-) requests MAY still be approved, but should not be a NERC defined "Must". E-Tag specifications may be changed to passively-APPROVE reliability adjustment requests to accommodate this standard, but that should only be automatic if the request is On-Time.
Response: The requirement was modified to require they notify their RC if a Reliability Adjustment Arranged Interchange is denied.		
MRO NERC Standards Review Subcommittee	Disagree	Language should be changed to On-Time Reliability Adjustment Requests. "Late" (and even past) requests MAY still be approved, but should not be a NERC defined "Must". E-Tag specifications may be changed to passively-APPROVE reliability adjustment requests to accommodate this standard, but that should only be automatic if the request is On-Time.
Response: The SDT has modified the requirement to indicate that a denial may only occur if not doing so would result in violation of one or more reliability standards.		
Duke Energy	Disagree	Language should be clarified such that only On-Time requests should be REQUIRED to be approved.
Response: The requirement was modified to require they notify their RC if a Reliability Adjustment Arranged Interchange is denied.		
NorthWestern Energy	Agree	NorthWestern agrees, but has a separate issue with R4. It is unclear what “associated with a direct-current tie operator” means in the context of the Requirement. Does this mean that a Balancing Authority that is a direct-current tie operator must follow the requirement, or any Balancing Authority that receives a Request for Interchange that includes a direct-current tie operator as a party to the Request for Interchange?
Response: The SDT has restructured the list of entities to make this clearer.		
Nebraska Public Power District	Disagree	Reliability Adjustment Requests should be approved period. To deny for lack of ramp will degrade the reliabiltiy of the interconnected system. For example, if an IROL is violated due to a sudden change in flow due to a contingency and a BA can deny the curtailment because it can't ramp in the change quick enough means there will be no relief when in fact there could be some relief if the change was ramped in as quickly as it could be. Another example is a DC tie trip between interconnections. The BA on the inverter side will experience a sudden and immediate loss of injection that probably will not be to serve load on its system and be expected to make up that loss just because another entity doesn't have enough ramp to meet the curtailment. This proposal doesn't make any sense from a reliability perspective. Curtailments for reliability

Organization	Yes or No	Question 10 Comment
		reasons MUST be approved.
Response: The requirement was modified to require they notify their RC if a Reliability Adjustment Arranged Interchange is denied.		
FirstEnergy	Disagree	Reliability Standards should not require the approval of market related transactions. The BA should only be required to deny a transaction if it cannot reliably implement the proposed transaction. The rules and requirements for approving transactions belong in the NAESB WEQ.
Response: The requirement was modified to require they notify their RC if a Reliability Adjustment Arranged Interchange is denied.		
Xcel Energy	Disagree	This question implies that the BA can choose to not approve the Reliability Adjustment. What constitutes the ability of a BA to support the magnitude of Interchange?
Response: The requirement was modified to require they notify their RC if a Reliability Adjustment Arranged Interchange is denied.		
SERC OC Standards Review Group	Disagree	We generally agree with the intent of this new requirement. However, in the case of a co-owned unit serving load in two BAs via Confirmed Interchange, if that unit tripped, this requirement appears to saddle the Source BA with deleterious CPS and DCS results. It would seem that the Sink BA would be required to approve a curtailment, regardless of ramp, in this case. This situation appears to be more complicated than could be resolved with this requirement.
Response: The requirement was modified to require they notify their RC if a Reliability Adjustment Arranged Interchange is denied.		
American Electric Power (AEP)	Agree	When it involves a reliability request, all applicable entities should try to accommodate to the best of their ability. Magnitude and ramp may actually be a less significant factor than unloading a transmission line or shedding load based on the situation.
Response: The requirement was modified to require they notify their RC if a Reliability Adjustment Arranged Interchange is denied.		

11. Requirements R5 and R6 of INT-006-4 list the criteria which a Sink Balancing Authority must use to determine whether an Arranged Interchange should be transitioned to a Confirmed Interchange or not:

R5. Each Sink Balancing Authority shall transition Arranged Interchange to Confirmed Interchange if any of the following conditions are met:

5.1 All entities associated with the Arranged Interchange have communicated their approval of the transition

5.2 The Arranged Interchange represents a Reliability Adjustment and the Source Balancing Authority, direct-current tie Operating Balancing Authority, and the Sink Balancing Authority associated with the Arranged Interchange have communicated their approval of the transition

5.3 The time period specified in Attachment 1, column B, has elapsed, all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transitions, and no other entities associated with the Arranged Interchange have communicated their denial of the transition.

R6. Each Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange if any of the following conditions are met:

6.1 The Arranged Interchange represents a Reliability Adjustment; the time period specified in Attachment 1, column B, has elapsed; and one or more of the following entities associated with the Arranged Interchange have not communicated their approval of the transition: the Source Balancing Authority, the direct-current tie Operating Balancing Authority, or the Sink Balancing Authority.

6.2 The Arranged Interchange does not represent a Reliability Adjustment; the time period specified in Attachment 1, column B, has elapsed; and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition

6.3 The Arranged Interchange does not represent a Reliability Adjustment, the time period specified in Attachment 1, column B, has elapsed, and any entity associated with the Arranged Interchange has communicated their denial of the transition

Do you agree that these criteria are correct? If no, what do you believe the correct criteria should be?

Summary Consideration: The majority of commenters agreed with the criteria. The SDT has found R5 to be redundant and it was removed.

Organization	Yes or No	Question 11 Comment
Ameren		

Organization	Yes or No	Question 11 Comment
Central Lincoln		
San Diego Gas & Electric		
South Carolina Electric and Gas		
Bonneville Power Administration	Agree	
California ISO	Agree	
Duke Energy	Agree	
GSOC & GTC Response	Agree	
Manitoba Hydro	Agree	
NERC Staff	Agree	
NorthWestern Energy	Agree	
PacifiCorp	Agree	
Platte River Power Authority	Agree	
SERC OC Standards Review Group	Agree	
Southern California Edison Co.	Agree	
WECC	Agree	
Xcel Energy	Agree	
PPL Energy Plus	Disagree	**R6: Sub-requirements 6.1 through 6.3 include a logical “and”. Should this be a logical “or”? **By specifying that the action shall not take place if “any” of conditions 61 though 6.3 are met, the**

Organization	Yes or No	Question 11 Comment
		logical operator is an "OR." **R7: The PSE (or other party originating Arranged Interchange) should be included in the list of parties notified of transition from Arranged to Confirmed. Please correct this omission. **The SDT has modified the requirement to include the PSE as suggested.**
Response:		
Functional Model Working Group		.
American Electric Power (AEP)	Agree	Active approval and reliability assessment should always occur.
Response: Such approval is required for all on-time and emergency Interchange as defined in R2 and R3. In other cases, there may not be enough time to do so.		
PJM	Disagree	As in the response to Question 8, the reliability issue is the approval/denial of the Interchange. The rationale for approval/denial is a business issue. There is no reliability reason for imposing "passive approval" of AIs. "Passive denials" would be more reliable because it only accepts actively approved AIs thereby avoiding operations in an unexamined system state.
Response: R5.3 only allows "passive approval" for market entities; reliability entities are not subject to "passive approval."		
Midwest ISO	Disagree	Language is needed to more accurately define direct-current tie Operating Balancing Authority, and its communication role, as that role may not be otherwise designated in the e-Tag's approval path. As well, a DC portion of the transmission path may not be designated on an e-Tag, and may be completely unknown to the Sink Balancing Authority.
Midwest ISO Stakeholder Standards Collaborators	Disagree	Language is needed to more accurately define direct-current tie Operating Balancing Authority, and its communication role, as that role may not be otherwise designated in the e-Tag's approval path. As well, a DC portion of the transmission path may not be designated on an e-Tag, and may be completely unknown to the Sink Balancing Authority.
MRO NERC Standards Review Subcommittee	Disagree	Language is needed to more accurately define direct-current tie Operating Balancing Authority, and its communication role, as that role may not be otherwise designated in the e-Tag's approval path. As well, a DC portion of the transmission path may not be designated on an e-Tag, and may be completely unknown to the Sink Balancing Authority.

Organization	Yes or No	Question 11 Comment
Response: The language has been modified to clarify this role. Additionally, any reference to a DC tie operator has been removed from this requirement.		
FirstEnergy	Disagree	Reliability Standards should not require the approval of market related transactions. The BA should only be required to deny a transaction if it cannot reliably implement the proposed transaction. The rules and requirements for approving transactions belong in the NAESB WEQ.
Response: The SDT does not believe that these requirement mandate approval of transactions for market entities. They only describe how to consider all the approvals and denials that have been made, as well as all appropriate time constraints, and determine whether or not the entire transaction should be transitioned into confirmed status or not. Commercial considerations are currently defined in NAESB WEQ-004.		
Nebraska Public Power District	Disagree	Requirements 5.2 and 5.1 must include the BA on both sides of a DC line that crosses between interconnections. For a DC tie that crosses an interconnection, the Balancing Authorities on both sides of the DC Tie are effectively source/sink for the transaction in that interconnection and for that reason alone need to approve or deny the transaction.
Response: We agree that the BAs on both sides of a DC tie crossing an interface must approve; that is required via R2. However, only one entity can be responsible for updating the overall status of the interchange, which is the Sink BA.		
Independent Electricity System Operator	Agree	The phrase 'shall not transition an Arranged Interchange to Confirmed Interchange' appropriately utilizes the currently defined terms, but it is not clear what action should be taken - should there be a transition to a state of denied?
ISO New Enlgand Inc.	Disagree	The phrase 'shall not transition an Arranged Interchange to Confirmed Interchange' appropriately utilizes the currently defined terms, but it is not clear what action should be taken. Should there be a transition to a state of denied?
Northeast Power Coordinating Council	Disagree	The phrase 'shall not transition an Arranged Interchange to Confirmed Interchange' appropriately utilizes the currently defined terms, but it is not clear what action should be taken - should there be a transition to a state of denied?
Response: Current software specifications detail the appropriate transitions to be taken. The intent of this requirement is to make it clear that it should not be transitioned to Confirmed Interchange (and it should not be included in NSI).		
Entergy	Agree	These criteria are correct, but Entergy would recommend adding an "if applicable" statement to the two requirements that list "the direct-current tie Operating Balancing Authority" since not all Reliability Adjustments include a DC tie.

Organization	Yes or No	Question 11 Comment
Response: The SDT has removed any specific reference to a DC tie in this requirement		

12. In Order 693, FERC issued directives that with regard to the INT standards, NERC include Reliability Coordinators and Transmission Operators as applicable entities, as well as require Reliability Coordinators and Transmission Operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the Sink Balancing Authorities' necessary transaction modifications before implementation. In response, the CI SDT proposes to add Requirements R8 and R9 of INT-006-3:

> **R8.** On a day-ahead basis, each Transmission Operator shall notify the associated Sink Balancing Authority(ies) of any Interchange modifications potentially required to mitigate any previously identified expected SOL or IROL exceedances.
>
> **R9.** On a day-ahead basis, each Reliability Coordinator shall notify the associated Sink Balancing Authority(ies) of any Interchange modifications potentially required to mitigate any previously identified expected IROL exceedances.

Do you believe that these new requirements will adequately address the FERC directive? If no, how do you think the directive should be addressed?

Summary Consideration: The majority of the commenters disagreed with the proposed inclusion of these new requirements in the INT standards, and many stated that they felt the requirements to be redundant with other standards. However, the SDT is concerned that the existing standards do not meet the FERC directive. Removed the proposed Transmission Operator and Reliability Coordinator requirements related to review of Confirmed Interchange prior to implementation. Instead, to address the FERC directive, the team is proposing revisions to defined terms as they apply to existing standards. These terms are Operational Planning Analysis and Real-time Assessment:

> **Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).**
>
> **Real-time Assessment: An examination of existing and expected system conditions, including Interchange, conducted by collecting and reviewing immediately available data.**

These defined terms are used in existing IRO-008-1 (Reliability Coordinator Operational Analyses and Real-time Assessments) and proposed TOP-002-3 (Operations Planning). In IRO-008-1, Requirement R1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider interchange when performing the study. Further, Requirement R2 specifies that the Reliability Coordinator must perform a Real-time Assessment. Again, by explicitly including "Interchange" in the definition of Real-time Assessment, the Reliability Coordinator must consider interchange when performing the study. When the

results of either of these studies indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3. TOP-002-3 contains requirement for the Transmission Operator to perform an Operational Planning Analysis (R1), develop plans for reliable operations based on the results of the Operational Planning Analysis and to notify other entities as to their role in those plans (R3).

Organization	Yes or No	Question 12 Comment
Ameren		
Central Lincoln		
PPL Energy Plus		
San Diego Gas & Electric		
South Carolina Electric and Gas		
American Electric Power (AEP)	Agree	
Bonneville Power Administration	Agree	
Manitoba Hydro	Agree	
Midwest ISO	Agree	
NERC Staff	Agree	
NorthWestern Energy	Agree	
Platte River Power Authority	Agree	

Organization	Yes or No	Question 12 Comment
Southern California Edison Co.	Agree	
Xcel Energy	Agree	
Functional Model Working Group		
PacifiCorp	Disagree	
Independent Electricity System Operator	Disagree	(1) Potentially required is not measurable **The SDT will consider this when developing the measures for related requirements.** (2) R8 is redundant with TOP-005-2 R2; and (3) R9 is redundant with IRO-001-1.1 R9 (all issues) & IRO-009-1 R3 (Day Ahead IROLs)& IRO-004-2 R1 (the BA must follow directives). **The SDT is concerned that the existing standards do not meet the FERC directive. The SDT believes that explicitly addressing the FERC directive in the IRO and TOP standards could be an equally effective alternative approach , and has drafted two new standards that do so.**
Response: Please see in-line responses.		
Northeast Power Coordinating Council	Disagree	(1) Potentially required is not measurable. **The SDT will consider this when developing the measures for related requirements.** (2) There is redundancy in R8 with TOP-005-2 R2. Also, R8 should be reworded for clarity. Suggest "Each Transmission Operator shall notify the Sink Balancing Authority(ies) when interchange schedules need to be modified to prevent a violation of a SOL or IROL." (3) There is redundancy in R9 with IRO-001-1.1 R9 (all issues), IRO-009-1 R3 (Day Ahead IROLs), and IRO-004-2 R1 (the BA must follow directives). Also, R9 should be reworded for clarity. Suggest "Each Reliability Coordinator shall notify the Sink Balancing Authority(ies) when interchange schedules need to be modified to prevent a violation of an IROL." Additional concerns are with respect to existing markets where submittal deadlines allow new interchange requests to occur up to 'near real-time'. In that type of market environment an estimate of the net interchange would be available on a day-ahead basis but there is no expectation of taking action to modify specific

Organization	Yes or No	Question 12 Comment
		interchange requests on a day-ahead basis. **The SDT is concerned that the existing standards do not meet the FERC directive. The SDT believes that explicitly addressing the FERC directive in the IRO and TOP standards could be an equally effective alternative approach , and has drafted two new standards that do so.**
Response: Please see in-line responses.		
MRO NERC Standards Review Subcommittee	Disagree	A. These requirements are not needed and will only duplicate existing requirements that adequately address the need to assess interchange transactions on a day-ahead basis. IRO-004-1 R1 already requires Reliability Coordinators to perform next day studies for “anticipated” conditions “to identify potential interface and other SOL and IROL violations. Day ahead energy schedules would clearly fall into anticipated conditions. IRO-004-1 R2 requires each Reliability Coordinator to “pay particular attention to parallel flows”. Again day ahead energy schedules fall into this parallel flows. IRO-004-1 R3 requires each Reliability Coordinator to develop action plans that may be required to alleviate IROL and SOL violations. One option for the action plans explicitly states curtailment of Interchange Transactions as an option. IRO-004-1 R6 requires the Reliability Coordinator to direct action to alleviation these IROL and SOL violations identified in the next day studies and IRO-004-1 R7 requires the Transmission Operator, Balancing Authority and Transmission Service Provider to comply with the directives based on the results of these next day studies. B. TOP-002-2 R5 requires Transmission Operators to plan to meet “scheduled system configuration, generation dispatch, interchange scheduling and demand patterns”. TOP-002-2 R11 requires the Transmission Operator to perform a next day study. Thus, a Transmission Operator would have to include day-ahead interchange schedules in its next day study in order to plan to meet them. Then TOP-002-2 R10 requires the Transmission Operator to plan to operate within IROLs and SOLs.
The SDT is concerned that the existing standards do not meet the FERC directive. The SDT believes that explicitly addressing the FERC directive in the IRO and TOP standards could be an equally effective alternative approach , and has drafted two new standards that do so. These concerns have been addressed in the new standards.		
Entergy	Disagree	How are the RCs and TOPs supposed to be able to know in advance of the real time flows exactly how many MWs of curtailment would be required in the case of a projected SOL or IROL exceedance? Since interchange schedules can be submitted until a few minutes before ramp start, then the day-ahead assessments have limited impact on maintaining real-time reliability conditions.
Response: These concerns have been addressed in the new standards by requiring both ongoing monitoring and day-ahead analysis.		

Organization	Yes or No	Question 12 Comment
SERC OC Standards Review Group	Disagree	How are the RCs and TOPs supposed to be able to know in advance of the real time flows exactly how many MWs of curtailment would be required in the case of a projected SOL or IROL exceedance? To what level of accuracy must these projections be made? What happens if the RC or TOP projects the wrong level of curtailment? Basically we don't feel that FERC's directive can be addressed without seriously damaging the energy market as we know it today.
Response: These concerns have been addressed in the new standards by requiring both ongoing monitoring and day-ahead analysis.		
FirstEnergy	Agree	However, R9 is contained in R8. The "or IROL" should be deleted from R8 as it is covered by R9.
Response: The SDT believes that TOPs should be considering both SOLs and IROLs, while the RCs should be only looking at IROLs. However, based on other comments, the SDT believes that explicitly addressing the FERC directive in the IRO and TOP standards could be an equally effective alternative approach, and has drafted two new standards that do so.		
GSOC & GTC Response	Disagree	It seems out of scope for a TOP to manage or predict next day real time flows in order to accurately curtail transactions.
Response: Note that thenew standards do not require curtailment, but only the notification of potential curtailments.		
California ISO	Disagree	R8 - the Requirement to have a TO notify a Sink BA of potential problems with modifications should be covered in the IRO Standards and not the Arranged Interchange Standards. R9 - The Requirement to have an RC notify a Sink BA of potential problems with modifications should be covered in the IRO Standards and not in the Arranged Interchange Standards.
Response: The SDT believes that explicitly addressing the FERC directive in the IRO and TOP standards could be an equally effective alternative approach, and has drafted two new standards that do so.		
PJM	Disagree	R8 is redundant with TOP-005-2 R2R9 is redundant with IRO-001-1.1 R9 (all issues) & IRO-009-1 R3 (Day Ahead IROLs)& IRO-004-2 R1 (the BA must follow directives).
Response: The SDT is concerned that the existing standards do not meet the FERC directive. The SDT believes that explicitly addressing the FERC		

Organization	Yes or No	Question 12 Comment
directive in the IRO and TOP standards could be an equally effective alternative approach, and has drafted two new standards that do so.		
WECC	Disagree	Requirement R9 is not necessary, as the RCs have enough latitude in the existing IRO-004 to mitigate problems identified in the next day studies results. This requirement should not create redundancy or confusion with IRO-004.
Response: The SDT is concerned that the existing standards do not meet the FERC directive. The SDT believes that explicitly addressing the FERC directive in the IRO and TOP standards could be an equally effective alternative approach, and has drafted two new standards that do so.		
Nebraska Public Power District	Disagree	The standard should apply to RC's since they have the wide area view. The transmission operator should not be responsible for montioring IROLs as the RC should have the big picture for them.
Response: TOPs are currently required to consider both SOLs and the IROLs within their system. TOPs are not expected to look at IROLs outside their system. RCs are required to look at IROLs across all the systems for which they are responsible.		
Midwest ISO Stakeholder Standards Collaborators	Disagree	These requirements are not needed and will only duplicate existing requirements that adequately address the need to assess interchange transactions on a day-ahead basis. IRO-004-1 R1 already requires Reliability Coordinators to perform next day studies for “anticipated” conditions “to identify potential interface and other SOL and IROL violations. Day ahead energy schedules would clearly fall into anticipated conditions. IRO-004-1 R2 requires each Reliability Coordinator to “pay particular attention to parallel flows”. Again day ahead energy schedules fall into this parallel flows. IRO-004-1 R3 requires each Reliability Coordinator to develop action plans that may be required to alleviate IROL and SOL violations. One option for the action plans explicitly states curtailment of Interchange Transactions as an option. IRO-004-1 R6 requires the Reliability Coordinator to direct action to alleviation these IROL and SOL violations identified in the next day studies and IRO-004-1 R7 requires the Transmission Operator, Balancing Authority and Transmission Service Provider to comply with the directives based on the results of these next day studies.TOP-002-2 R5 requires Transmission Operators to plan to meet “scheduled system configuration, generation dispatch, interchange scheduling and demand patterns”. TOP-002-2 R11 requires the Transmission Operator to perform a next day study. Thus, a Transmission Operator would have to include day-ahead interchange schedules in its next day study in order to plan to meet them. Then TOP-002-2 R10 requires the Transmission Operator to plan to operate within IROLs and SOLs.
Response: The SDT is concerned that the existing standards do not meet the FERC directive. The SDT believes that explicitly addressing the FERC		

Organization	Yes or No	Question 12 Comment
directive in the IRO and TOP standards could be an equally effective alternative approach, and has drafted two new standards that do so.		
Duke Energy	Disagree	We believe that these requirements are more appropriately addressed in the IRO standards, rather than in the INT standards.
Response: The SDT believes that explicitly addressing the FERC directive in the IRO and TOP standards could be an equally effective alternative approach, and has drafted two new standards that do so.		
ISO New Enlgand Inc.	Disagree	We do not believe these new requirements are appropriate for the following reasons: (1) "Potentially required" is not measurable **The SDT will consider this when developing the measures for related requirements.** (2) R8 is redundant with TOP-005-2 R2; and (3) R9 is redundant with IRO-001-1.1 R9 (all issues) & IRO-009-1 R3 (Day Ahead IROLs)& IRO-004-2 R1 (the BA must follow directives). (4) In existing economic markets, where submittal deadlines allow new interchange requests to occur up to 'near realtime', an estimate of the net interchange would be available for coordination on a day-ahead basis but there is no expectation of taking action to modify specific interchange requests on a day-ahead basis as the requirements indicate. **The SDT is concerned that the existing standards do not meet the FERC directive. The SDT believes that explicitly addressing the FERC directive in the IRO and TOP standards could be an equally effective alternative approach, and has drafted two new standards that do so. Note that the cocners regarding timing have been addressed in the new standards by requiring both ongoing monitoring and day-ahead analysis.**
Response: Please see in-line responses.		

13. In INT-010-2, the CI SDT has added Requirement R4 to specify when it is appropriate to use Reliability Adjustment Requests for Interchange (i.e., curtailment):

R4. Balancing Authorities, Transmission Service Providers, and Reliability Coordinators shall only utilize a Reliability Adjustment Request for Interchange in response to the following

4.1 Loss or non-performance of Generation supplying the Interchange

4.2 Loss of Load being served by the Interchange

4.3 Loss of one or more Transmission Facilities

4.4 An actual or potential SOL or IROL exceedance

4.5 Any real-time reliability concern related to a specific Confirmed Interchange, provided that concern is supported by evidence.

Do you believe these limitations are appropriate? If not, what other reasons should be included?

Summary Consideration: The majority of commenters agreed that these limitations were appropriate.

Some commenters suggested that market operators should be allowed to make reliability-based adjustments to interchange for commercial reasons. The SDT disagreed, and responded that those adjustments should instead be handled through non-reliability-based adjustments.

Organization	Yes or No	Question 13 Comment
Ameren		
Central Lincoln		
San Diego Gas & Electric		
South Carolina Electric and Gas		
American Electric Power (AEP)	Agree	
Bonneville Power Administration	Agree	
Duke Energy	Agree	

Organization	Yes or No	Question 13 Comment
Entergy	Agree	
GSOC & GTC Response	Agree	
Manitoba Hydro	Agree	
Midwest ISO	Agree	
Midwest ISO Stakeholder Standards Collaborators	Agree	
NERC Staff	Agree	
MRO NERC Standards Review Subcommittee	Agree	
NorthWestern Energy	Agree	
PacifiCorp	Agree	
Platte River Power Authority	Agree	
SERC OC Standards Review Group	Agree	
Southern California Edison Co.	Agree	
Xcel Energy	Agree	
Functional Model Working Group		
Independent Electricity System Operator	Disagree	(1) The requirement assumes that it defines the complete set of exemptions. However, the IRO and TOP standards do a better job by mandating that the RC and TOP take actions for IROLs not just during an event but also if an event is anticipated. **The SDT believes this is addressed in R4.4 by allowing for “potential” exceedances.**

Organization	Yes or No	Question 13 Comment
		(2) This requirement is redundant with IRO-009-1 R4 **The SDT does not believe that IRO-009-1 R4 is duplicative of this requirement. IRO-009-1 does not provide any detail with regard to Interchange transactions.**
Response:		
ISO New Enlgand Inc.	Disagree	(1) The requirement assumes that it defines the complete set of exemptions. However, the IRO and TOP standards do a better job by mandating that the RC and TOP take actions for IROLs not just during an event but also if an event is anticipated. **The SDT believes this is addressed in R4.4 by allowing for "potential" exceedances.** (2) This requirement is redundant with IRO-009-1 R4 **The SDT does not believe that IRO-009-1 R4 is duplicative of this requirement. IRO-009-1 does not provide any detail with regard to Interchange transactions.** (3) These specific reasons do not allow the BA or TSP to make an adjustment is made because of failed checkout or the economics of a transaction in a market. Where are those adjustments allowed? **Economics of a market are a commercial concern, not a reliability concern, and should be addressed through the use of a non-reliability modification.**
Response:		
Northeast Power Coordinating Council	Disagree	(1) The requirement assumes that it defines the complete set of exemptions. However, the IRO and TOP standards do a better job by mandating that the RC and TOP take actions for IROLs not just during an event but also if an event is anticipated. **The SDT believes this is addressed in R4.4 by allowing for "potential" exceedances.** (2) This requirement is redundant with IRO-009-1 R4.What about when an adjustment is made because of failed checkout, or the economics of a transaction in a market? **Economics of a market are a commercial concern, not a reliability concern, and should be addressed through the use of a non-reliability modification.**
Response:		

Organization	Yes or No	Question 13 Comment
PPL Energy Plus	Disagree	**This standard needs to apply to Reliability Coordinators if the PPL-proposed R5 (below) is included. **There may be occasions when a BA or TSP will not respond to a PSE request under R4. Because of possible non-response by the BA and/or TSP, R5 should be added to require RC's to respond to a RFI from PSE's (or possibly requests from all non-BA's or non-TSP's).
Response: The SDT is uncertain of how you propose to include the RC in this process. However, we note that BAs and TSPs are now required in the standards to respond to such requests, and compliance will be enforcing such behaviors.		
FirstEnergy	Disagree	4.1 and 4.2 are contractual arrangements that do not necessarily equate to a reliability issue. R4.3 may or may not represent a reliability concern. **The SDT believes that 4.1 thought 4.4 are all operational conditions that have a direct impact on the capabilities of the BES. While they themselves may not create a reliability problem, they definitely impact the status of the BES, and their inclusion in the requirement is appropriate.** The statement "provided that concern is supported by evidence" in R4.5 is heavy handed. It implies that Mr. BA, TSP, or RC may cut the transaction, but you better make sure you have evidence to support that decision. By requiring these entities to adjust the transaction for "Any real-time reliability concern related to a specific Confirmed Transaction" you directly require evidence to prove compliance with the requirement. This makes the phrase "provided that concern is supported by evidence" in R4.5 redundant and unnecessary. It should be deleted. **The SDT has removed this as suggested.**
Response:		
Nebraska Public Power District	Agree	Agree assuming that a DC tie is considered a Transmission Facility.
Response: The CISDT concurs that a DC Tie is a transmission facility.		
California ISO		No comment
WECC	Disagree	The RC needs to have the ability to use all its available tools to determine how to mitigate any potential issues on the BES. This requirement appears to unnecessarily limit the use of a Reliability Adjustment Request, and thus restrict the RCs use of this tool.
Response: The SDT believes that inclusion of 4.5 addresses this concern.		

Organization	Yes or No	Question 13 Comment
PJM	Disagree	This is a Business issue not a reliability issue.
Response: The SDT believes that 4.1 thought 4.4 are all operational conditions that have a direct impact on the capabilities of the BES. While they themselves may not create a reliability problem, they definitely impact the status of the BES, and their inclusion in the requirement is appropriate. Note that this standard allows the use of the Reliability Adjustment for these reasons. Entities that believe these are business issues may choose to use the non-reliability modification process instead.		

14. In INT-009-2 R1, the CI SDT has proposed that:

No more than one hour prior to each operating hour, each Balancing Authority shall ensure that for that operating hour, the composite of its Confirmed Interchange energy profiles (and any associated modifications to Confirmed Interchange), excluding Dynamic Schedules, with each Adjacent Balancing Authority is:

- Agreed to by that Adjacent Balancing Authority,
- Identical in magnitude to that of the Adjacent Balancing Authority, and
- Opposite in sign to that of the Adjacent Balancing Authority.

The CI SDT chose not to specify a method to reach agreement when conflicts arise, instead assuming that entities will develop their own procedures to resolve conflicts. Should this requirement be modified to include a default procedure that must be used if one does not already exist? If yes, please offer proposals for such a procedure.

Summary Consideration: The majority of commenters agreed that no default procedure is needed.

One commenter suggested that the requirements were unclear, since they required BAs to "agree," but did not assign blame to a single entity if parties do not agree. The SDT disagreed, and said the standard was clear: failing to reach agreement was a failure of both parties.

Organization	Yes or No	Question 14 Comment
Ameren		
Central Lincoln		
Functional Model Working Group		
PPL Energy Plus		
San Diego Gas & Electric		
NorthWestern Energy	Agree	
Bonneville Power Administration	Disagree	

Organization	Yes or No	Question 14 Comment
Duke Energy	Disagree	
Manitoba Hydro	Disagree	
Nebraska Public Power District	Disagree	
NERC Staff	Disagree	
Platte River Power Authority	Disagree	
Southern California Edison Co.	Disagree	
Xcel Energy	Disagree	
Midwest ISO	Disagree	Midwest ISO "agrees" to the intent of the requirement and that no default procedure is necessary. The requirement language should remove the words "No more than one hour". Scheduled interchange may be agreed to prior to that OH-1 along with other hours of static MW flow, for example. If this previously agreed-upon interchange schedule has not changed, no further communication should be needed.
Midwest ISO Stakeholder Standards Collaborators	Disagree	Midwest ISO "agrees" to the intent of the requirement and that no default procedure is necessary. The requirement language should remove the words "No more than one hour". Scheduled interchange may be agreed to prior to that OH-1 along with other hours of static MW flow, for example. If this previously agreed-upon interchange schedule has not changed, no further communication should be needed.
Response: The SDT has eliminated the language indicating this must be done no more than one hour ahead.		
California ISO		No comment
FirstEnergy	Agree	NOTE: We clicked "Agree" in the on-line comment form to signify that we agree with the SDT's choice to not specify a method to reach agreement when conflicts arise. However, it is not unreasonable that a business rule be written that requires resolution of conflicts procedure. It is also reasonable to allow reliability entities to not implement a transaction that has not been agreed to by everyone prior to implementation.
Response: The SDT concurs in general, provided that ALL entities not implement the transaction.		
GSOC & GTC Response	Disagree	Requirements should specify what must be accomplished - not tell how an entity should accomplish it.

Organization	Yes or No	Question 14 Comment
		Procedures should be left up to the entities.
Response: Thank you for your supportive comment.		
South Carolina Electric and Gas	Disagree	SCEG believes the Confirmed Interchange profile is not required to be checked out hourly, but upon changes in schedules
Response: The SDT has eliminated the language indicating this must be done no more than one hour ahead.		
MRO NERC Standards Review Subcommittee	Disagree	The NSRS "agrees" to the intent of the requirement and that no default procedure is necessary. The requirement language should remove the words "No more than one hour". Scheduled interchange may be agreed to prior to that first operating hour along with other hours of static MW flow, for example. If this previously agreed-upon interchange schedule has not changed, no further communication should be needed.
Response: The SDT has eliminated the language indicating this must be done no more than one hour ahead.		
American Electric Power (AEP)	Agree	The present SPP structure and EIS Market needs to be addressed, while still having individual BAs needs addressed to meet the intent of this Standard.
Response: No explanation has been provided of how the SPP concerns are or are not addressed. Without such explanation, the CISDT in uncertain how to proceed.		
PJM	Disagree	The proposed requirement does not meet the FERC directive for clarity. The requirement must be clear regarding who is responsible for compliance. As written it is not clear which BA would be held non-compliant for a disagreement. The proposed requirement requires the BAs to ensure the validity of the data. The BAs need only decide on whether or not they can implement the Arranged Interchange based on the data. If the data is invalid the BAs must reject the request. As noted in the response to Q1, a better approach is to maintain a single requirement that if there is no agreement then there is no implementation.
Response: The CISDT disagrees. Both entities would be in violation. Entities are free to determine whatever approach they choose to achieve agreement (no agreement = no implementation, most conservative, split-the-difference, etc…). However, agreement must be achieved or both entities will be considered to have failed the requirement.		
Entergy	Disagree	The standards should not specify the “how” of interchange checkout between BAs. Forcing adjacent BAs to perform hourly checkouts seems burdensome if Confirmed Interchange Schedules do not change between hours. Entergy recommends changing this requirement to remove the “No more than one hour prior to each operating hour” language in order to allow flexibility in checkout practices.

Organization	Yes or No	Question 14 Comment
Response: The SDT has eliminated the language indicating this must be done no more than one hour ahead.		
Independent Electricity System Operator	Disagree	The word "composite" is confusing. Does it mean the net BA to BA interchange or individual BA to BA interchange? **Composite is intended to mean "net with that neighbor" and the SDT has added a defined term Composite Confirmed Interchange. The SDT was concerned with using the term "Net," as it generally refers to total imports/exports out of a BA, not total per interface.** The default when there is a disagreement is that the BAs must check each Interchange Schedule and not just Net Interchange. **The SDT agrees that many entities will check each interchange schedule. However, the SDT is not requiring such procedures to be undertaken.**
Response:		
ISO New Enlgand Inc.	Disagree	The word "composite" is confusing. Does it mean the net BA to BA interchange or individual BA to BA interchange? **Composite is intended to mean "net with that neighbor" and the SDT has added a defined term Composite Confirmed Interchange. The SDT was concerned with using the term "Net," as it generally refers to total imports/exports out of a BA, not total per interface.** The default when there is a disagreement is that the BAs must check each Interchange Schedule and not just Net Interchange. **The SDT agrees that many entities will check each interchange schedule. However, the SDT is not requiring such procedures to be undertaken.** Should special consideration need to be given in the requirements (or only the measures and compliance) for known and planned hardware/software outages that could impact this process for more than one hour? **No. Regardless of software outages, the Interchange scheduled between adjacent BAs must match.**
Northeast Power Coordinating Council	Disagree	The word "composite" is confusing. Does it mean the net BA to BA interchange or individual BA to BA interchange? **Composite is intended to mean "net with that neighbor" and the SDT has added a defined term**

Organization	Yes or No	Question 14 Comment
		Composite Confirmed Interchange. The SDT was concerned with using the term "Net," as it generally refers to total imports/exports out of a BA, not total per interface. The default when there is a disagreement is that the BAs must check each Interchange Schedule and not just Net Interchange. **The SDT agrees that many entities will check each interchange schedule. However, the SDT is not requiring such procedures to be undertaken.** Should special consideration need to be given in the requirements (or only the measures and compliance) for known and planned hardware/software outages that could impact this process for more than one hour? **No. Regardless of software outages, the Interchange scheduled between adjacent BAs must match.**
Response:		
PacifiCorp	Disagree	The words "no more than one hour prior to each operating hour" are ambiguous and could potentially be interpreted to preclude a preschedule check-out. To clarify, PacifiCorp suggests that the language read "at least one hour prior to each operating hour...." or, in the alternative, the words "no more than one hour prior to each operating hour" should be eliminated entirely.
Response: The SDT has eliminated the language indicating this must be done no more than one hour ahead.		
WECC	Disagree	this requirement should NOT be modified. It is appropriate as is.
Response: Thank you for your supportive comment.		
SERC OC Standards Review Group	Disagree	We agree with the SDT's position. However, we assert that ramps should be verified to be identical as well.
Response: Thank you for your supportive comment. The SDT has created a definition of "Composite Confirmed Interchange" that includes ramping.		

15. The CI SDT has made significant attempts to consolidate, clarify, and organize the standards such that they accurately reflect the manner in which the industry currently operates and mandate appropriate levels of performance. Are there any requirements that you think are missing from these standards? If yes, please elaborate.

Summary Consideration: The majority of commenters agreed that there were no missing requirements.

Organization	Yes or No	Question 15 Comment
Ameren		
Central Lincoln		
Independent Electricity System Operator		
ISO New Enlgand Inc.		
San Diego Gas & Electric		
South Carolina Electric and Gas		
Bonneville Power Administration	Disagree	
Duke Energy	Disagree	
Entergy	Disagree	
Functional Model Working Group		
GSOC & GTC Response	Disagree	
Manitoba Hydro	Disagree	
Midwest ISO	Disagree	

Organization	Yes or No	Question 15 Comment
Midwest ISO Stakeholder Standards Collaborators	Disagree	
NERC Staff	Disagree	
MRO NERC Standards Review Subcommittee	Disagree	
Platte River Power Authority	Disagree	
SERC OC Standards Review Group	Disagree	
Southern California Edison Co.	Disagree	
Xcel Energy	Disagree	
Nebraska Public Power District	Disagree	As noted above there are areas that are not clear and consise and at times are confusing. Also the notes to allow exceptions to timing requirements based on auditors discretion will not result in even treatment at times when extreme circumstances exist.
Response: Thank you for your comments. The SDT has removed the notes to allow exceptions to the timing requirements.		
Northeast Power Coordinating Council	Disagree	No comments.
WECC	Disagree	No requirements are missing.
PacifiCorp		None at this time
NorthWestern Energy	Disagree	NorthWestern is not aware of any further requirements necessary for reliability.
FirstEnergy	Agree	NOTE: We clicked "Agree" in the on-line comment form to signify that we do not think there are any requirements missing. However, it appears throughout the standards development that the drafting team is mixing business practices with reliability-related issues. A review by the team of the proposed standards to ensure that business practices are managed by NAESB and reliability issues are housed in the NERC

Organization	Yes or No	Question 15 Comment
		Standards is appropriate and necessary.
Response: Thank you for your comments.		
American Electric Power (AEP)	Agree	Please refer to question 17 for additional comments on the rewrite of the Standards.
Response: Please see question 17 for responses.		
California ISO	Agree	Retain IA role and function. Retain Arranged and Implemented Interchange.
Response: The SDT, along with the majority of entities that answered Question 2 of this form, do not agree the IA is required. The standard does retain Arranged and Implemented Interchange.		
PJM	Disagree	See response to Question 17.
Response: Please see question 17 for responses.		
PPL Energy Plus		The CI SDT should be commended for their tremendous efforts to correctly assign responsibilities to the entities involved in Coordinated Interchange. PPL offers the following comments to support the CI SDT in their endeavors. 1)Since INT-011 describes what might be the first step in the sequence of events to establish Interchange, the rest of the standards should be numbered sequentially (i.e. INT-012, etc.). **The concepts in INT-011 were moved into the Guidelines and Technical Basis section of INT-006.** 2)The CI SDT needs to be prepared for the situation where all new standards are not approved by the FERC or all old standards are not approved for retirement by the FERC. We recognize that this is not the intent, but it remains a possibility. A solution may be to link the retirements to the approvals or combine the retirement into the new approved standard etc. **This will be incorporated into the Implementation plan for the standards.** INT-004-3 Dynamic Schedules Please re-insert R2 from INT-004-2 that requires a release and reload of interchange that has been curtailed. Please assure that in all cases, the PSE's are kept informed of all curtailments and reloads. **INT-006 R6.5 requires that PSEs be included on the transition of any Arranged Interchange.**

Organization	Yes or No	Question 15 Comment
		R1: Loads with dynamic schedules are still the responsibility of the Sink BA who should be included as a responsible party. The old requirement that Sink BA's arrange for dynamic schedules for Joint Owned Units (JOUs) and inadvertent payback is implied, but not stated. Please clearly state that the entity responsible for Arranging Dynamic Interchange for JOUs and inadvertent payback is the Sink BA in the new standards. **The SDT does not believe there is a reliability reason that Sink BA's be required to arrange dynamic schedules for JOUs and Inadvertent Payback.** R2.3 requires the PSE to modify the dynamic schedule for reliability concerns communicated by the RC/TOP to the PSE's. However, it does not appear that these INT standards require the RC/TOP to notify the PSE that a reliability concern exists and that the associated modification(s) or reload(s) must take place. Please insert such notification to the affected PSE(s) into the requirement. **The SDT has changed the requirement to indicate that LSEs much make changes only if the receive notification of the need for such changes.** INT-006-4 Evaluation of Interchange R1: The reasoning behind R1.3 (less than the three-minute time) is not clear. In fact, R1.2 and R1.3 seem to be at odds with one another. Would the CI SDT please review the concepts under R1 and clarify the wording of sub-requirements 1.2 and 1.3? **The SDT has simplified R1 to address this concern.** R3.1 Item 1): Should "remaining for the TSR" be "remaining on the TSR"? **The SDT has modified the langue to address this concern.** R3.1 Item 3): This requirement needs to allow for situations where the physical transmission path is intact, but a software tool does not have the right database model. In this case, a responsible entity should be allowed the discretion to allow the Interchange to flow regardless of the underlying software model.

Organization	Yes or No	Question 15 Comment
		The standard does not mandate the use of or adherence to any software model. To the extent an operator knows that the path is valid, it should approve the Arranged Interchange, regardless of what any model indicates. R6: Sub-requirements 6.1 through 6.3 include a logical “and”. Should this be a logical “or”? **By specifying that the action shall not take place if “any” of conditions 6.1 though 6.3 are met, the logical operator is an “OR.”** R7: The PSE (or other party originating Arranged Interchange) should be included in the list of parties notified of transition from Arranged to Confirmed. Please correct this omission. **INT-006 R6.5 requires that PSEs be included on the transition of any Arranged Interchange..** INT-009-2 Implementation of Interchange R2.2: the word “Plus” is used to describe inclusion of a number (the Dynamic schedule) which may or may not be POSITIVE. It may be best to use a word other than “Plus” such as “including” or “summation” in order to provide clarification and accuracy. **The SDT has removed the word “plus” and addressed the requirement by requiring the inclusion of the two values.** INT-010-2 Initiating and modifying Interchange for Reliability This standard needs to apply to Reliability Coordinators if the PPL-proposed R5 (below) is included. There may be occasions when a BA or TSP will not respond to a PSE request under R4. Because of possible non-response by the BA and/or TSP, R5 should be added to require RC’s to respond to a RFI from PSE’s (or possibly requests from all non-BA’s or non-TSP’s). **The SDT is uncertain of how you propose to include the RC in this process. However, we note that BAs and TSPs are now required in the standards to respond to such requests, and compliance will be enforcing such behaviors.**

Organization	Yes or No	Question 15 Comment
		INT-011-1 Interchange Coordination Support (i.e. electronic tools to support interchange). R1: Please add wording to indicate that the Sink BA's must be responsible for providing Arranged Interchange if a PSE cannot author an etag. **The SDT does not agree that it is the responsibility of the Sink BA to do so unless that arrangement has been agreed to by the involved parties. It is up to the PSE to make arrangements with whatever entities necessary to ensure they can submit their Arranged Interchange.**
Response:		

16. Are you aware of any conflicts between the proposed standards and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement? If yes, please explain your answer.

Summary Consideration: The majority of entities found no conflicts. Some entities suggested that pre-emptive curtailment was inappropriate; the team removed requirements related to this based on earlier comments.

Organization	Yes or No	Question 16 Comment
Ameren		
Central Lincoln		
PJM		
PPL Energy Plus		
San Diego Gas & Electric		
South Carolina Electric and Gas		
Functional Model Working Group		
Southern California Edison Co.	Agree	
Bonneville Power Administration	Disagree	
GSOC & GTC Response	Disagree	
Manitoba Hydro	Disagree	
Midwest ISO	Disagree	
Midwest ISO Stakeholder Standards Collaborators	Disagree	

Organization	Yes or No	Question 16 Comment
Nebraska Public Power District	Disagree	
NERC Staff	Disagree	
MRO NERC Standards Review Subcommittee	Disagree	
Platte River Power Authority	Disagree	
Xcel Energy	Disagree	
ISO New Enlgand Inc.	Disagree	As provided in Q9, Q12 and Q13 above, there may be special ‘interpretation’ required to ensure these requirements, as written, do not conflict with some FERC approved markets.
Northeast Power Coordinating Council	Disagree	As provided in Q9, Q12 and Q13 above, there may be special ‘interpretation’ required to ensure these requirements, as written, do not conflict with some FERC approved markets.
Response: The SDT is not aware of the details of the potential conflicts that have been alluded to. If entities can provide the SDT with such detail, we will work to see if we can identify an appropriate solution.		
Duke Energy	Agree	In questions 9 and 12, the SDT appears to essentially require a preemptive TLR anywhere from hours to a day in advance of the materialization of real time flows in excess of the real time capability of the transmission grid. This would inappropriately reduce the liquidity and optionality afforded by the current physical rights of tariffs for transmission service.
Response: Regarding question 9, the SDT has eliminated the case requiring pre-emptive curtailment as part of the approval process. **Regarding question 12, the SDT has removed the requirements in question and will be addressing the directive though a change in the definitions of the assessments performed by the RC and TOP. Removed the proposed Transmission Operator and Reliability Coordinator requirements related to review of Confirmed Interchange prior to implementation. Instead, to address the FERC directive, the team is proposing revisions to defined terms as they apply to existing standards. These terms are Operational Planning Analysis and Real-time Assessment:** **Operational Planning Analysis: An analysis of the expected system conditions for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).** **Real-time Assessment: An examination of existing and expected system conditions, including Interchange, conducted by collecting and**		

Organization	Yes or No	Question 16 Comment
reviewing immediately available data. **These defined terms are used in existing IRO-008-1 (Reliability Coordinator Operational Analyses and Real-time Assessments) and proposed TOP-002-3 (Operations Planning). In IRO-008-1, Requirement R1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider interchange when performing the study. Further, Requirement R2 specifies that the Reliability Coordinator must perform a Real-time Assessment. Again, by explicitly including "Interchange" in the definition of Real-time Assessment, the Reliability Coordinator must consider interchange when performing the study. When the results of either of these studies indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3. TOP-002-3 contains requirement for the Transmission Operator to perform an Operational Planning Analysis (R1), develop plans for reliable operations based on the results of the Operational Planning Analysis and to notify other entities as to their role in those plans (R3).**		
Entergy	Agree	In questions 9 and 12, the SDT appears to essentially require a preemptive TLR anywhere from hours to a day in advance of the materialization of real time flows in excess of the real time capability of the transmission grid. The preemptive curtailments should occur more closely to real-time so that the assessment is more meaningful to real-time system conditions.
Response: Regarding question 9, the SDT has eliminated the case requiring pre-emptive curtailment as part of the approval process. **Regarding question 12, the SDT has removed the requirements in question and will be addressing the directive though a change in the definitions of the assessments performed by the RC and TOP. Removed the proposed Transmission Operator and Reliability Coordinator requirements related to review of Confirmed Interchange prior to implementation. Instead, to address the FERC directive, the team is proposing revisions to defined terms as they apply to existing standards. These terms are Operational Planning Analysis and Real-time Assessment:** **Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).** **Real-time Assessment: An examination of existing and expected system conditions, including Interchange, conducted by collecting and reviewing immediately available data.** **These defined terms are used in existing IRO-008-1 (Reliability Coordinator Operational Analyses and Real-time Assessments) and proposed TOP-002-3 (Operations Planning). In IRO-008-1, Requirement R1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider interchange when performing the study. Further, Requirement R2 specifies that the Reliability Coordinator must perform a Real-time Assessment. Again, by explicitly including "Interchange" in the definition of Real-time Assessment, the Reliability Coordinator must consider interchange when performing the study. When the results of either of these studies indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3. TOP-002-3 contains requirement for the Transmission Operator to perform an Operational Planning Analysis (R1), develop plans for reliable operations**		

Organization	Yes or No	Question 16 Comment
based on the results of the Operational Planning Analysis and to notify other entities as to their role in those plans (R3).		
SERC OC Standards Review Group	Agree	In questions 9 and 12, the SDT appears to essentially require a preemptive TLR anywhere from hours to a day in advance of the materialization of real time flows in excess of the real time capability of the transmission grid. This would inappropriately reduce the liquidity and optionality afforded by the current physical rights of tariffs for transmission service.
Response: Regarding question 9, the SDT has eliminated the case requiring pre-emptive curtailment as part of the approval process. **Regarding question 12, the SDT has removed the requirements in question and will be addressing the directive though a change in the definitions of the assessments performed by the RC and TOP. Removed the proposed Transmission Operator and Reliability Coordinator requirements related to review of Confirmed Interchange prior to implementation. Instead, to address the FERC directive, the team is proposing revisions to defined terms as they apply to existing standards. These terms are Operational Planning Analysis and Real-time Assessment:** **Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).** **Real-time Assessment: An examination of existing and expected system conditions, including Interchange, conducted by collecting and reviewing immediately available data.** **These defined terms are used in existing IRO-008-1 (Reliability Coordinator Operational Analyses and Real-time Assessments) and proposed TOP-002-3 (Operations Planning). In IRO-008-1, Requirement R1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider interchange when performing the study. Further, Requirement R2 specifies that the Reliability Coordinator must perform a Real-time Assessment. Again, by explicitly including "Interchange" in the definition of Real-time Assessment, the Reliability Coordinator must consider interchange when performing the study. When the results of either of these studies indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3. TOP-002-3 contains requirement for the Transmission Operator to perform an Operational Planning Analysis (R1), develop plans for reliable operations based on the results of the Operational Planning Analysis and to notify other entities as to their role in those plans (R3).**		
PacifiCorp		None at this time
NorthWestern Energy	Disagree	NorthWestern is not aware of any such conflicts.
WECC	Disagree	Not aware of any conflicts.
FirstEnergy	Agree	NOTE: We clicked "Agree" in the on-line comment form to signify that we are not aware of any conflicts

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 16 Comment</th></tr>
<tr><td></td><td></td><td>between the proposed standards and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.</td></tr>
<tr><td>California ISO</td><td>Agree</td><td>SDT draft change run counter to present IA contracts in the West, negotiated and entered into in good faith.</td></tr>
<tr><td colspan="3">Response: The SDT has representation from WECC members, none of which who seem to share this concern. Note that nothing in these standards would prevent WECC from continuing to provide Interchange Coordination services to its members.</td></tr>
<tr><td>Independent Electricity System Operator</td><td>Disagree</td><td>We are not aware of any conflicts.</td></tr>
<tr><td>American Electric Power (AEP)</td><td>Agree</td><td>Yes, different Market models and structure, such as SPP.</td></tr>
<tr><td colspan="3">Response: The SDT is not aware of the details of the potential conflicts that have been alluded to.   If entities can provide the SDT with such detail, we will work to see if we can identify an appropriate solution.</td></tr>
</table>

17. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed standards**.**

Summary Consideration: Entities asked clarifying questions, reiterated their prior comments, and identified typographical and organization errors which the team addressed.

Organization	Yes or No	Question 17 Comment
Entergy		
GSOC & GTC Response		
Manitoba Hydro		
Midwest ISO		
Midwest ISO Stakeholder Standards Collaborators		
MRO NERC Standards Review Subcommittee		
Platte River Power Authority		
PPL Energy Plus		
South Carolina Electric and Gas		
Southern California Edison Co.		
Ameren		1. The SDT should address if pseudo-ties should be shown so that they can be included in reliability tool (IDC) analysis. If they are to be excluded, please add a footnote stating it. **INT-004 now addresses pseudo-ties.** 2. In INT-10, R4, an RFI acronym is used that is not defined either explicitly or parenthetically. Please include a definition.

Organization	Yes or No	Question 17 Comment
		This word is defined currently in the NERC Glossary, under "Request for Interchange." 3. In INT-11, be able to transmit "electronically" is unacceptable. Does this mean by email? This is electronic. If it means to use e-tag, please clearly state it as electronically is not good enough. **Tagging has used several communication protocols in the past, including e-mail. The SDT believes that it would be inappropriate to commit to a particular tool or technology within the standard. The industry has currently elected to use E-Tag to meet the requirements of the standard, and this is acceptable. To the extent the industry wishes to develop an alternate implementation that can meet these requirements, that is also acceptable. Note that NAESB currently has an implementation guide that defines the tools that can be used to meet the standards.**
Response:		
San Diego Gas & Electric		Although the term, "Load Balancing Authority" appears in the proposed new standard INT-011-1, and is also used in the approved Reliability Standard IRO-006-3, there is no definition of this term in the Glossary of Terms Used in Reliaibility Standards. A definition should be created. The use of the term, "Confirmed Interchange" seems to be different than the definition currently listed in the Glossary of Terms Used in the Reliability Standards. In addition, the present term still refers to the IA. A new or revised definition of Confirmed Interchange is necessary.
Response: The SDT has removed its use of "Load" BA and replaced it with "Sink" BA. **The definition of Confirmed Interchange has been updated, as have several other definitions related to Interchange.**		
FirstEnergy		FE has the following additional comments: 1. It seems the drafting team's statement, "In cases where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes, the Compliance Monitor may exercise discretion in determining whether or not a violation of this requirement has occurred." assigns a compliance auditor an authority that they already have. This statement seems unnecessary. The requirement should allow the reliability entity to suspend market operations and Standards of Conduct when extreme situations such as where Interchange Coordination is non-functional or has been degraded due to coincidental, accidental, or malicious causes. The circumstances cited truly represent a threat to reliability on an emergency level that 888 and 889 envisioned with the inclusion of a provision to suspend market operations during an emergency. **The SDT agrees that the Compliance Enforcement Authority has this capability as you have described. The change to the requirements associated with the distribution times in INT-006**

Organization	Yes or No	Question 17 Comment
		alleviated the need for the language provided previously in the footnotes. . 2. INT-004-3 – (a) Applicability and Req. R2.3 - Although the standard applicability section and Req. R2.3 lists the Transmission Operator (TOP), the TOP does not appear to have any responsibilities. Main Req. R2 is only applicable to the Purchasing-selling Entity. We suggest that the SDT remove the TOP from the applicability section A.4. **The SDT has eliminated the extraneous entities from the applicability.** (b) In Req. R1, the phrase "Load-serving, Purchasing-Selling Entity...", we feel that the phrase is awkwardly written and may be misinterpreted to place responsibility on the functional entity "Load-Serving Entity". We suggest rewording R1 as follows: "The Purchasing-Selling Entity that provides Load associated with a Dynamic Schedule shall ensure...". **The SDT has modified the requirement similarly to the suggestion provided.** 3. Effective Date - We feel that the proposed effective date of the "first day of the first calendar quarter following the date this standard is approved by regulatory authorities..." does not provide the entities appropriate time to implement these extensive changes. From a compliance evidence standpoint, the changes will create much additional work due to all the revised, transferred, and retired requirements. Also, INT-011-1 is a new standard and there may be responsible entities that will need adequate time to provide the required support for interchange coordination. We suggest the SDT consider increasing the implementation period by at least two calendar quarters. **The SDT has modified this to be the "first day of the second calendar quarter…"** 4. We noticed that the VRF and Time Horizons are not shown in the draft requirements. Is the SDT planning to develop these in a later draft? **Yes.**
Response:		
Independent Electricity System Operator		General: There are several places where the Load Balancing Authority is used. Why is this term used instead of Sink Balancing Authority? **The SDT has replaced "Load" BA with "Sink" BA** INT-004: Please describe why an AI created for the based on the maximum MW value of a Dynamic Schedule should never need to be modified. This seems to allow everyone to put in a maximum value and leave unchanged for the duration of the interchange.

Organization	Yes or No	Question 17 Comment
		The standard requires it to be modified if the Reliability Coordinator requires it be modified. Additionally, is should be noted that entities may only use the maximum if the do NOT have a forecast. If they do have a forecast, it must be used. INT-006: The term IA still exists in the timing tables. Also, the table requires distribution of Late and ATF AIs when the language in the requirements is only applicable to on-time AI. **The SDT has removed the IA from the tables. Timing information not directly related to the requirement ahs been provided for convenience, but is not enforceable.** INT-009: The addition of the phrase 'and maintain the generation-to-load balance' does not seem to be consistent with the requirements of standards; there are no requirements related to this action. Suggest removing. **To the extent Interchange is present, Interchange is a part of Balancing. Unequal Interchange will result in an unbalanced system. As such, we believe this language to be appropriate.** INT-010: The purpose of INT-010 indications that some Interchange Schedules should be exempt from compliance with 'other Interchange Standards'. The requirements within INT-010 do not seem to be consistent with this purpose. **INT-010 specifies responsibilities and actions that are different from those described in INT-006 and INT-009.** INT-011: The Reliability Coordinator is in the Applicability section but is not mentioned in the requirements **The SDT has modified the applicability to eliminate this inconsistency.**
Response:		
ISO New Enlgand Inc.		General: There are several places where the Load Balancing Authority is used. Why is this term used instead of Sink Balancing Authority? **The SDT has replaced "Load" BA with "Sink" BA.** INT-004: Please describe why an AI created for the based on the maximum MW value of a Dynamic Schedule should never need to be modified. This seems to allow everyone to put in a maximum value and leave unchanged for the duration of the interchange. **The standard requires it to be modified if the Reliability Coordinator requires it be modified. Additionally, is should be noted that entities may only use the maximum if the do NOT have a forecast. If they do have a forecast, it must be used.** INT-006: The term IA still exists in the timing tables. Also, the table requires distribution of Late and ATF AIs

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Response:		
Northeast Power Coordinating Council		In INT-004-3 R1, the term "Load-serving, Purchasing-Selling Entity" is used and can cause confusion by making this standard appear to apply to Load-serving Entities as well as Purchasing-Selling Entities. A Purchasing-Selling Entity should have to adhere to these requirements whether or not it is serving retail load. "Load-serving" should be stricken from this requirement. **The SDT has replaced this language with words that more accurately reflect the intent of the requirement.** There are several places where the Load Balancing Authority is used. Why is this term used instead of Sink Balancing Authority? **The SDT has replaced "Load" BA with "Sink" BA.** INT-004: Please describe why an AI created for the based on the maximum MW value of a Dynamic Schedule should never need to be modified. This seems to allow everyone to put in a maximum value and leave unchanged for the duration of the interchange. **The standard requires it to be modified if the Reliability Coordinator requires it be modified. Additionally, is should be noted that entities may only use the maximum if the do NOT have a**

Organization	Yes or No	Question 17 Comment
		forecast. If they do have a forecast, it must be used. INT-006: The term IA still exists in the timing tables. Also, the table requires distribution of Late and ATF AIs when the language in the requirements is only applicable to on-time AI. **The SDT has removed the IA from the tables. Timing information not directly related to the requirement has been provided for convenience, but is not enforceable.** INT-009: The addition of the phrase 'and maintain the generation-to-load balance' does not seem to be consistent with the requirements of standards; there are no requirements related to this action. Suggest removing. **To the extent Interchange is present, Interchange is a part of Balancing. Unequal Interchange will result in an unbalanced system. As such, we believe this language to be appropriate.** INT-010: The purpose of INT-010 indications that some Interchange Schedules should be exempt from compliance with 'other Interchange Standards'. The requirements within INT-010 do not seem to be consistent with this purpose. **INT-010 specifies responsibilities and actions that are different from those described in INT-006 and INT-009.** INT-011: The Reliability Coordinator is in the Applicability section but is not mentioned in the requirements **The SDT has modified the applicability to eliminate this inconsistency.**
Response:		
California ISO		INT-004-3 Comments: In the WECC, the effective date is based on the "First day of the first calendar quarter following the date this standard is approved by applicable authorities." **The SDT is not sure of the intent of this comment.** R1.1 - The term "Load Serving, Purchasing-Selling Authority" should be changed to "Load-Serving Entity" as defined in the NERC Glossary. **The SDT has replaced this language with words that more accurately reflect the intent of the requirement.** There is a question pertaining to "Reloading Transactions" in Question #7 of the accompanying questionnaire. **Please see Question 7 for response.**

Organization	Yes or No	Question 17 Comment
		INT-006-4 Comments: R1 - Appears to be missing the RFI distribution to the PSE. **The PSE has been added to the list of entities that receive the final state of the RFI, in R6.5 of the latest posted version of standard.** R2.1 - Missing valid energy product code is a valid reason for denial. **The SDT does not believe missing such a code is an invalid reason for denial, but believes it is not mandatory for denial.** R4 - Direct-current Tie Operator or Direct-Current Tie Operating Balancing Authority should be defined and added to the NERC Glossary. **The SDT believes the term “DC tie operator” is self explanatory. The SDT has replaced DC Tie Operating BAs with “BAs associated with DC tie operators”.** R8 - The requirement to have a TO notify a Sink BA of potential problems with modifications should be covered in the IRO Standards and not the Coordinate Interchange Standards. **The SDT agrees with these comments, and believes that this is addressed in proposed TOP-002-3. The requirements specify that the TOP shall perform an Operational Planning Analysis, develop a plan to operate within IROLs and to notify all parties of their role within the plan.** INT-009-2 Comments: Requirement numbering (R numbering and R sub-numbering) needs to be consistent between this and other INT Standards. **The numbering has been fixed.** R2 - The NERC definition defines the Net Interchange Schedule, it does not define Net Scheduled Interchange, although many use the terms interchangeably. **Both terms are currently in the NERC Glossary.** What is meant by the use of the word “term”? **The word “term” is intended to have the common mathematical meaning, which is “a unitary or compound expression connected with another by a plus or minus sign.”** INT-010-2 Comments: There is a need to identify the default entity that creates the tag in requirements R1-R3 as the Load Serving

Organization	Yes or No	Question 17 Comment
		Entity. **The SDT believes that from a reliability perspective, there is no need to define who creates a tag.** INT-011 Comments: R1.1 - “Load Balancing Authority” should be replaced with the defined term “Sink Balancing Authority” as defined in the NERC Glossary. **The SDT has made this changes as suggested.** R2.3 - Validate Requests for Interchange (RFI) section is missing the Energy Product validation used to determine if additional reserves are needed and is a valid reason to deny a tag. **The SDT does not believe it is an invalid reason to deny the tag, only that it is not required that all tags without an energy product must be denied.** R2.4 - “Validate request to modify Interchange” is silent on the entities that have the rights/requirements for approval or denial. Curtailments should only require Source and Sink to approve that type of modification. Does “modify” really mean a market and/or reliability adjust? If so, there needs to be a change to the terminology. **This is addressed in INT-006.** R2.5 - Should indicate which entities are distributed the RFI. **This is addressed in INT-006.** R2.6 - Should indicate which entities are distributed the RFI. **This is addressed in INT-006.**
Response:		
Central Lincoln		INT-004-3 R1 introduces a new entity type called the "Load serving, Purchasing-Selling Entity." This entity was left off the applicability list for the standard, and does not yet exist in the functional model or the registry criteria. Who exactly does R1 apply to?
Response: The SDT has replaced this language with words that more accurately reflect the intent of the requirement.		
American Electric Power (AEP)		INT-004-3 Rewrite Comments: The purpose statement should also include pseudo tie interchange besides the dynamic schedule reference. While BAL-005-0.1b deals the metering aspect, it does not address that in many cases the pseudo tie interchange is not being accounted for appropriately in the NERC IDC. This was a

Organization	Yes or No	Question 17 Comment
		very apparent finding from the Northeast Blackout of 2003. The unscheduled flows and reliability impact of pseudo ties still remains a problem today. Regardless of where the BA has the pseudo tie is contractually modeled to, the affecting source or sink impact on reliability still comes from the response factor of actual physical location. **The latest version of the standards posted for comment now address pseudo-ties.** R1: If the Load-serving PSE is only responsible for ensuring the RFI is submitted to the Sink BA, who is responsible for making sure the Source BA has the same confirmed schedule intent to ensure generator to load balance? This could imply the Source BA does not need to know, while it is presently a function of the Interchange Authority and its electronic process. **These concerns are addressed in INT-006.** R2 and its sub-requirements: The BES does not operate to average energy profile values. It operates to real-time values and changes. Average energy profile is a Market accounting and settlement term, which has no place in real-time operation or its tools/process, such as IDC or interchange scheduling, for managing congestion or reliability impact. **As dynamic schedules are constantly varying, there is no simple way to account for their real-time variability in the Interchange process. Accordingly, the standard requires that they be recorded at an “average” value to aid in coordination and reliability analysis.** R2.3: The average energy profile term is used in the preceding requirements, yet the hourly energy profile term is used in R2.3. All reliability impact is based on the actual operating value at a specific time, regardless of what is on the forecasted dynamic schedule value. These actual operating values are not continually identified in the IDC, which accounts for the unscheduled flow issue. This is why it is extremely important to continually have the forecast dynamic schedule match the impact of the actual operating value. Actual operating values can different greatly from forecasted dynamic average energy profile, enabling the root cause to not be identified in IDC and forcing other interchange to be curtailed instead. **As dynamic schedules are constantly varying, there is no simple way to account for their real-time variability in the Interchange process. Accordingly, the standard requires that they be recorded at an “average” value to aid in coordination and reliability analysis.** The intent of Standard INT-004-3 is to address a needed reliability process. However, it does not cover the impact of unscheduled flows caused by pseudo tie interchange. The requirement parameters for deviation are reactive in addressing the actual operating impact, just as the IDC curtailment process is sometimes reactive. **The latest version of the standards posted for comment now address pseudo-ties .** Since the maximum actual energy cannot exceed the transmission reservation that has already been reliably

Organization	Yes or No	Question 17 Comment
		assessed in the OASIS reservation/priority process, we recommend the PSE continually matching forecasted dynamic schedule to actual operating value and communicate to the IDC. It might be impossible to do this on forecasted dynamic schedule interchange that frequently changes with significant magnitude. The only way to realistically accomplish identification and communication of reliability impact to the IDC would be to somehow send these actual interchange values. **Such improvements are beyond the scope of this first phase of development, by will be considered in the next phase. Than you for your suggestions.** INT-006-4 Rewrite Comments: R1 Proposing that the Sink Balancing Authority shall be exclusively responsible for distributing Arranged Interchange is totally contradictory to the Interchange Scheduling process and purpose of the Interchange Authority in the present NERC functional model. It appears to put all the burden of arranging and distributing AI to the Source BA. This concept appears to be going back to the days of and former model of Control Area and bundled utility, in which adjacent CA's confirmed interchange schedules. In today's model, open access Market and all of the granular applicable involved entities in the NERC functional model and process, it does not seem realistic for the Sink BA to be responsible for distribution in an electronic E-Tag process environment. Many NERC approved Regional Transmissions Organizations (RTOs) have different models and interchange scheduling tools, processes and congestion management mechanisms. They are also registered as the Interchange Authority in the NERC functional model. There is nothing wrong with the current electronic scheduling process (E-Tag and Vendor Tagging Authority). NERC and the Industry would be better served to clearly define what the applicable IA entity really is and means. Possibly, NERC should be the IA responsible for the electronic process and backup for distributing the necessary interchange scheduling and reliability information to the applicable entities defined in its functional. It makes sense for the current RTOs, such as PJM, SPP, etc., to be registered as the IA for their areas. It should be up to them how this interchange information is distributed within the intent of the NERC Reliability Standard through their choice of vendor, electronic tagging authority specifications and contract to meet the Requirements. The second option should be NERC itself. How can a Sink BA be responsible in an open access/Market environment with all of the multiple entities involved? The Sink BA does not actually make the Request for Interchange (RFI) or arrange the interchange. The affiliated PSE or designated CPSE does through its Tagging Authority service and the NERC Interchange Authority E-Tag process. **The Functional Model has created a conceptual role of "Interchange Authority." From a purely academic standpoint, this is logical and reasonable. However, from a practical standpoint, several challenges emerge during implementation:** - **Interchange Authority functions occur not on a global basis, but on a per-transaction basis. While balancing is assigned to a specific area, and transmission operation is assigned to a**

Organization	Yes or No	Question 17 Comment
		particular set of equipment, Interchange Coordination is dynamic in nature. This is different from all the other functions, and clearly not feasible to implement in the real world. In other words, while you CAN have a single IA for all of North America, the model allows for a different IA to be created for each transaction created. - **NERC only has jurisdiction over the users, owners, and operators of the BES. This excludes any entity that is not a user/owner/operator of the BES from performing the IA function. Accordingly, this limits the ability of many third parties to perform this function independently. Additionally, NERC already offers ways for third parties to perform the function (through JROs or through contractual delegation).** - **Much like the Interconnection Time Monitor, the Interchange Authority is a role with little benefit to the entity performing the function but with significant compliance risk. Entities have suggested that it is appropriate to simply make the Sink Balancing Authority the "default" IA and then force all Sink BAs to register as IAs. While we do see a bureaucratic difference between this and simply assigning the tasks directly to the Sink BA, we see no practical difference that is being provided. However, not directly assigning this to the Sink BA does result in questions and uncertainty from those entities who do not wish to perfom the task. Accordingly, we believe it is clearer to simply assign the task to the Sink BA and let them elect how to perform it – directly; via a JRO with another entity (such as a group of BAs consolidating their Interchange coordination functions under one umbrella); or contractually (such as a BA hiring a service provider to perform their Interchange Coordination functions).** **The functional model is exactly that - a model. The standards are intended to implement the model. The SDT does not see any inconsistency with assigning the functions of the IA directly to the Sink Balancing Authority. This is currently the manner in which Interchange Transactions are managed, and will result in more clarity and reduced ambiguity for the industry.** R2.1: There are many aspects that can compromise a Source or Sink BA's ability to determine the meeting of the magnitude of Interchange and ramp. With the different RTO and ISO models, especially with respect to Market protocols and impacting granular entities, such as Independent Generator Operators, how can a BA solely determine capability of supporting ramp? For example: In the Southwest Power Pool/RTO and Energy Imbalance Schedule Market model SPP is the tariff administrator, transmission service provider, scheduling control area (SCA - according to the OATI IA tool) and it deploys Market Participant GOPs. Yet it has individual membership BAs responsible for demonstrating the ability to meet ramp and magnitude of Interchange to meet performance standards involving generation to load balance, while the Market is deploying GOP resources that could contradict this effort. **NERC does not recognize a "Scheduling Control Area" as a registered entity. Based on the description provided, it would appear that either 1.) SPP is taking over some of the BA functions of its entities, or 2.) SPP is acting as a BA that has delegated some of its functions to local BAs. In either**

Organization	Yes or No	Question 17 Comment
		case, this could be accomplished through improved coordination as part of a JRO or through a variance to the standards if it can be shown that an alternative approach meets or exceeds the reliability objectives of the standards. Applicability: Agree with adding the 4.3 Reliability Coordinator and 4.4 Transmission Operator entities. **Thank you for your supportive comment.** INT-009-2 Rewrite Comments: In the case of Markets, such as SPP, where there are continual market interval Interchange changes of significance impact on ACE and deployments to independent GOPs that do not follow the intent of meeting generation to load balnce, who is responsible for confirming before implementation into the member BAs' ACE equations? Also, see comments above in R2.1. These types of Market models compromise the intent of meeting the generation to load concept meant to be addressed in the Balancing and Interchange Standards. **Based on the description provided, it would appear that either 1.) SPP is taking over some of the BA functions of its entities, or 2.) SPP is acting as a BA that has delegated some of its functions to local BAs. In either case, this could be accomplished through improved coordination as part of a JRO or through a variance to the standards if it can be shown that an alternative approach meets or exceeds the reliability objectives of the standards.** Retirement of Standards Comments:The current IA process and concept should remain but needs to be better defined. If not, NERC should administer the IA process and electronic Interchange distribution of RFI and AI to the affected/applicable reliability entities for assessment and approval. **As discussed, the SDT does not believe the independent IA (non-JRO and non-contractually delegated) to be implementable form a practical standpoint. To the extent it is determined to be practical in the future, the SDT believes revisiting the standards (either as a change or through a variance) would be appropriate.** **The SDT does not believe a majority of the industry would be supportive of NERC providing a single IA for all entities.**
Response:		
Xcel Energy		INT-009 R2 has “or alternate control process” in parentheses. Believe this should be deleted. ACE is a measurement for compliance that may be used for control purposes. It is up to the entity to comply with the remaining NERC standards, including performance. The entity may be able to accomplish that without incorporating the NSI into their control process. The requirement should only state that the term be used in

Organization	Yes or No	Question 17 Comment
		the BA's ACE, though this may be unecessary as ACE is defined in other standards. **The SDT agrees that entities may not necessarily use ACE for control; however, we do not agree that accurate control can be accomplished without having NSI as an input into that control process. We do not presume to specify any other aspects of the control equation, but to not include NSI in the control equation would indicate that entities are not controlling to schedule, which is what this requirement intends to prohibit.** INT-011-1 R1.1 refers to a Load Balancing Authority. Should this be Sink Balancing Authority? With respect to requiring an entity to be able to "electronically" perform functions, consider the need to state that is must be compatible with the Interchange Coordination tools. **The concepts of INT-011 have been moved into the Guidelines and Technical Basis section of INT-006.** In general: - the standards are wordy and written in a manner that is difficult to understand. **The SDT is working to streamline the language, but notes that some of the requirements are intended to eliminate procedural requirements and focus on delivered results. As such, it is critical that the delivered results be correctly defined, so that no undesired outcomes are created.** - Is there an ability to use a manual process in lieu of an electronic system if the Interchange Coordination tools are not available? If so, do the requirements need to cover this situation? **The requirements do still apply even if the electronic systems, typically used, are not available; however manual processes can be used. The Guidelines and Technical Basis section of INT-006 recommend having a backup plan that is known by all affected parties and could be implemented as needed.**
Response:		
Nebraska Public Power District		Measures are missing for most standards. They need to be developed or the requirements removed. There should not be a requirement that cannot be measured.
Response: The SDT has developed measures in the next draft of the standards.		
NERC Staff		NERC believes the draft requirements are very well written, and offers its compliments to the CISDT. **Thank you for your supportive comments.** There are several terms used in the standards that do not appear to be defined in the NERC Glossary: "On-time Arranged Interchange," "Reliability Adjustment," "SOL," "Transmission Facilities," "Entity Registry," and

Organization	Yes or No	Question 17 Comment
		"Load Balancing Authority." NERC suggests the CISDT either define these terms or consider alternate wording in the standard. **On-time is defined in the timing tables. The SDT has added a footnote to make this clear.** **The SDT has replaced the generic term "reliability adjustment" with the defined term "Reliability Adjustment Arranged Interchange."** **The standard no longer used the abbreviation "SOL."** **Transmission and Facilities are separately defined terms in the NERC glossary.** **The SDT has removed the reference to the "Entity Registry" and replaced it with implementation-neutral language.** **The SDT has replaced "Load Balancing Authority" with "Sink Balancing Authority."** In general, NERC asks the members of the CISDT and the industry at large if there is truly a need to have the all the details specified in the draft standards as mandatory and enforceable requirements. While we believe there is value in the industry agreeing on a common set of tools and practices related to Interchange coordination, we question if those tools and practices should be required in a reliability standard and monitored for compliance. **The SDT has reviewed the standards, and believes they are appropriate.**
Response:		
PacifiCorp		None at this time
NorthWestern Energy		NorthWestern appreciates this opportunity participate in the commenting process.
Response: Thank you for your comments.		
Duke Energy		- Given that the BA has been given additional responsibilities, where and how are the specifications for INT transactions defined? The drafting team needs to address this issue **The SDT is uncertain as to what new responsibilities are being referenced. Please provide further detail to the CISDT directly.** - INT-009-2 Requirement R1 - for this requirement, you should not have to re-confirm schedules that have

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 17 Comment</th></tr>
<tr><td></td><td></td><td>not changed from previous hours.
The SDT has modified the requirement to not require verification every hour.</td></tr>
<tr><td colspan="3">Response:</td></tr>
<tr><td>PJM</td><td></td><td>PJM would suggest the SDT directly address the issues that they the SDT propose to remedy:
1. Define the data that must be coordinated for reliability
- Magnitude
- Start and end times
- Rate of change
- Source/sink
2. Distinguish between coordination tools and reliability entities. For example:
- Require that BAs only implement CONFIRMED INTERCHANGE; then as sub-requirements list the acceptable means of doing that:
- By using an Interconnection-wide tool that the BAs will use as the basis for demonstrating that they met the coordination requirement for each CI; or
- By BA-to-adjacent BA checkout where using the same inter-area net values as confirmation that they met the coordination requirement
3. Seek NERC approval to make the data in the interconnection wide tool available to the RC for review. PJM does not agree that the RC should be included in the interchange coordination process because the TOP and RC currently (IRO-001-1 R3 to R9) has the authority to reject any schedule at any time that it deems the system is or will at risk (IRO-004-2 R1) Let NAESB define and maintain the timing requirements and the boundaries for what can and cannot be used for Dynamic Schedules. [As long as both BAs agree to the magnitude of a schedule, the system will be in balance.]</td></tr>
<tr><td colspan="3">Response: The SDT believes it is directly addressing these issues and making those distinctions. We also believe the specifics related to the RC are being addressed through the proposed AAR, and will aid in improving clarity and will result in a more unambiguous set of standards.</td></tr>
<tr><td>Functional Model Working Group</td><td></td><td>PLEASE NOTE THAT THE FMWG IS SUBMITTING COMMENTS ONLY TO QUESTION 2
The survey form does not provide the option to deselect the agree/disagree entry once it is checked.
All other responses should really be NO RESPONSE.</td></tr>
</table>

Organization	Yes or No	Question 17 Comment
Response: Thank you for your comments.		
Bonneville Power Administration		Some of the revised Standards (e.g., INT-006-4) tend to have wordy requirements that make them not only difficult to interpret but also make demonstration of compliance more complex. Shorter, very specific language is preferred.
Response: The SDT will consider your comments as the drafting of the standard continues.		
SERC OC Standards Review Group		The SDT needs to review all INT standards, particularly INT-004-3, in regards to the applicability of the entities for those requirements. "The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Response: The SDT will continue to do so.		
WECC		WECC is generally in favor of the revised INT Standards that are currently posted on the NERC Web site for a 45-day comment period, especially the removal of the IA from the INT standards. WECC recognizes that individual members within WECC may submit comments in opposition of this, and respects the rights of those members to differ with WECC's opinion Another general comment is that the compliance measures and data requirements need to be clearly defined in order for entities to fully understand their responsibilities, and for Regional Entities to understand and develop a reasonable audit approach for the standards. WECC thanks the CISDT for the opportunity to provide comments.
Response: Thank you for your supportive comments,		

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed on (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.

Description of Current Draft

This is the second draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	July 2013
Recirculation ballot	October 2013
BOT adoption	November 2013
File standard with regulatory authorities.	December 2013

Effective Dates

First day of the second calendar quarter beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Dynamic Schedule: A time-varying energy transfer that is updated in real time and included in the Net Interchange Scheduled term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).

Pseudo-Tie: A time-varying energy transfer that is updated in real time and included in the Net Interchange Actual term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

Standards impacted by the above revisions: BAL-002-WECC-2, BAL-003-0.1b and BAL-005-0.2b

Request for Interchange - A collection of data as defined in the NAESB Business Practice Standards, to be submitted to the Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.

Arranged Interchange - The state where the Sink Balancing Authority has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).

Confirmed Interchange - The state where the Sink Balancing Authority has verified the Arranged Interchange.

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule.

Intermediate Balancing Authority - A Balancing Authority involved in an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.

A. Introduction

1. **Title:** **Dynamic Transfers**
2. **Number:** INT-004-3
3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.
4. **Applicability:**
   4.1. Balancing Authority
   4.2. Load-Serving Entity
5. **Background:**

This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of dynamic transfers.

- R1 and R2 are modified from INT-004-2 to incorporate requirements to submit a RFI for each Pseudo-Tie that are comparable to the existing requirements for Dynamic Schedules. The requirements in this standard to create an RFI ensure that all entities involved are aware of the dynamic transfer and agree that that the various responsibilities associated with the dynamic transfer have been agreed upon.
- R2 is modified to separate the triggers for the review of the dynamic transfer and when a modification is required for the dynamic transfer.
- R3 and R4 are created to address the coordination that must occur between all entities involved prior to the initial implementation of a Pseudo-Tie. The responsibilities that must be determined when establishing a Pseudo-Tie extend to such items as Disturbance Control Standard (DCS) recovery, load shedding, transmission and ancillary services, and load forecasting. The Guidelines and Technical Basis section of this standard summarizes the considerations that must be given when establishing any dynamic transfer.

B. Requirements and Measures

R1. Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie at either: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]

- The expected average MW profile for each hour if a forecast for the Dynamic Schedule or Pseudo-Tie is available, or
- The expected maximum MW profile for each hour if no forecast for the Dynamic Schedule or Pseudo-Tie is available.

M1. The Load-Serving Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that RFIs were submitted for Dynamic Schedules and Pseudo-Ties on-time and either at the expected average profile or the expected maximum profile for each hour. (R1)

R2. Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is reviewed and updated if needed for the next available scheduling hour and future hours if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

2.1. For Confirmed Interchange using the expected average MW profile, if the average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile for the next hour indicated in the Confirmed Interchange by more than 10%.

2.1.1. The Load-Serving Entity shall ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours if the review performed in R2 indicates that a deviation of more than 10% will persist.

2.2. For Confirmed Interchange using the expected average MW profile, if the average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated in the Confirmed Interchange by more than 25 MW and this deviation is expected to continue in future hours.

2.2.1. The Load-Serving Entity shall ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours if the review performed in R2 indicates that a deviation of more than 25 MW will persist.

2.3. Receipt of notification from a Reliability Coordinator or Transmission Operator that a deviation from the hourly energy profile indicated in the Confirmed Interchange, regardless of magnitude, is a reliability concern and requires that the Confirmed Interchange be updated.

M2. The Load-Serving Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it reviewed and updated as needed its RFIs when the deviation met or exceeded the criteria Requirement R2, Parts 2.1- 2.3. (R2)

Rationale for R3: This Requirement is intended to ensure that a Pseudo-Tie is properly established. This requirement will be effective until the NAESB registry accepts Pseudo-Tie registrations.

R3. Each Balancing Authority shall verify that each of the following conditions has been met prior to approving a Pseudo-Tie Arranged Interchange in order to support congestion management capabilities [1] [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]:,

3.1. Any Intermediate Balancing Authority that schedules in-kind losses in real-time related to the Pseudo-Tie has identified how losses will be accounted for over their Balancing Authority Area.

3.2. Each of the Balancing Authority's associated Reliability Coordinators (in the Eastern Interconnection) or associated Transmission Operators (in the Western Interconnection) has confirmed that sufficient information to reliably manage the Pseudo-Tie has been provided.

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it approved a Pseudo-Tie Arranged Interchange subject to Requirement R3, Parts 3.1-3.2. (R3)

R4. Each Balancing Authority shall verify the Pseudo-Tie is registered in the NAESB Electric Industry Registry prior to approving a Pseudo-Tie Arranged Interchange in order to support congestion Management. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

Rationale for R4: This Requirement is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. This requirement will become effective when the NAESB registry accepts Pseudo-Tie registrations. Until such time, R3 will be in effect.

M4. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only approved a Pseudo-Tie Arranged Interchange the Pseudo-Tie is registered in the NAESB Electric Industry Registry. (R4)

[1] The ERCOT and Hydro Quebec Interconnections have not been included in this requirement, as they are single Balancing Authority Interconnections and only connected to other Balancing Authorities through HVDC tie-lines.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Load-Serving Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Load-Serving Entity shall maintain evidence to show compliance with R1, and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 and R4 for the most recent 3 calendar months plus the current month.

If a Load-Serving Entity or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The Load-Serving Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie and had a forecast for that Dynamic Schedule or Pseudo-Tie, but did not ensure that an RFI with the expected average MW profile for each hour was submitted as an on-time Arranged Interchange to the Sink Balancing Authority. OR The Load-Serving Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie and did not have a forecast for that Dynamic Schedule or Pseudo-Tie, but did not ensure that an RFI with the expected maximum MW profile for each hour was submitted as an on-time Arranged Interchange to the Sink Balancing

						Authority.
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for the next available scheduling hour or failed to ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.
R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority approved a Pseudo-Tie Arranged Interchange for a Pseudo-Tie and any of Parts 3.1, 3.2 were not met.
R4	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority approved a Pseudo-Tie Arranged Interchange for a Pseudo-Tie that is not registered in the NAESB Electric Industry Registry.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-ties are accounted for by all parties as actual interchange and dynamic schedules are accounted for as scheduled interchange. The obligations of the entities involved in each type of dynamic transfer are dependent on the type of dynamic transfer selected. These guidelines provide items that should be considered when determining which type of dynamic transfer should be utilized for a given situation.

General Considerations when establishing and implementing dynamic transfers:

- During the setup of a dynamic transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
    - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the Table 1.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services FERC OATT Schedules 3–6 and other ancillary services as	Attaining BA	Native BA

required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE frequency bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BA(s) by the pseudo-tie	The Attaining BA should include the load from its dynamic schedule as a part of its forecast load to set frequency bias requirement. The Native BA should change its load used to set frequency bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.

Description of Current Draft

This is the second draft of the proposed standard posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	July 2013
Recirculation ballot	October 2013
BOT adoption	November 2013
File standard with regulatory authorities.	December 2013

Effective Dates

First day of the second calendar quarter beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking
1.0	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2.0	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3.0	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3.0	July 1, 2010	Approved by FERC	Revised
4.0	TBD	Adopted by the NERC Board Of Trustees	Revised

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed Revised Definitions:

Arranged Interchange - The state where the Sink Balancing Authority has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).

Confirmed Interchange - The state where the Sink Balancing Authority has verified the Arranged Interchange.

Adjacent Balancing Authority - A Balancing Authority Area that is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

Intermediate Balancing Authority - A Balancing Authority involved in an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule.

Source Balancing Authority - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for the resulting Interchange Schedule.

Proposed New Definition:

Reliability Adjustment Arranged Interchange - Request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Evaluation of Interchange Transactions**
2. **Number:** INT-006-4
3. **Purpose:** To ensure that entities conduct a reliability assessment of each Arranged Interchange before it is implemented.
4. **Applicability:**
   4.1. Balancing Authority
   4.2. Transmission Service Provider
5. **Background:**

This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-006-4 continues to be the reliability assessment of Interchange Transactions prior to their implementation.

The content of INT-006-4 has been revised and expanded in the following manner:

- R1 was created by moving and revising R1 from INT-005-3, which has been retired as part of the project. This requirement ensures that Arranged Interchange is properly distributed to the relevant parties for reliability assessment.
- R2 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Balancing Authority must deny the transition.
- R3 was created by revising R1 from INT-006-3. This requirement ensures that Transmission Service Providers involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Transmission Service Provider must deny the transition.
- R4 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange.
- R5 was created by moving and revising R1 from INT-007-1, which has been retired as part of the project. This requirement lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange.
- R6 was created by moving and revising R1 from INT-008-3, which has been retired as part of the project. This requirement lists the entities to which a Sink

Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.

- Attachment 1 timing tables for WECC were modified to address scheduling on a 15 minute basis

B. Requirements and Measures

R1. Each Sink Balancing Authority shall distribute each Arranged Interchange to the Source Balancing Authority, each Intermediate Balancing Authority, and each Transmission Service Provider included in the Arranged Interchange so that these entities can conduct a reliability assessment of the Arranged Interchange before the Arranged Interchange is implemented. When distributing Arranged Interchange, each Sink Balancing Authority shall ensure that each distribution exceeding the times specified in Attachment 1, Column A, does not result in either of the following: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Same-day Operations, Real-time Operations*]

1.1. On-time[1] Arranged Interchange where not all Balancing Authorities and Transmission Service Providers either approved or denied as specified in R2, R3, and R4.

1.2. On-time Arranged Interchange being transitioned to Confirmed Interchange without enough time to incorporate into scheduling systems prior to ramp start as specified in Attachment 1, Column D.

M1. The Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it distributed each Arranged Interchange to the listed entities and that for those distributions that exceed the times specified in Attachment 1, Column A, neither Part 1.1 or Part 1.2 occurred. (R1)

R2. With the exception of the provisions in R5, each Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange shall[2] approve or deny its transition to Confirmed Interchange prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, Column B. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations, Real-time Operations*]

> Rationale for R2: Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. R2.1 and R2.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny for other reasons. If the conditions described in R2.1 or R2.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

[1] As defined in INT-006-4 Attachment 1.

[2] Balancing Authorities are not required to provide responses to any other requests.

2.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

2.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the scheduling path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

M2. Unless otherwise addressed by the provisions in Requirement R4, each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R2)

R3. Each Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange, shall[3] approve or deny its transition to Confirmed Interchange prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, Column B. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations, Real-time Operations*]

Rationale for R3: TSPs must take action on a received Arranged Interchange within a certain time frame. R3.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in R3.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

3.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M3. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R3)

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[3] Transmission Service Providers are not required to provide responses to any other requests.

R4. Each Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, Column B. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations, Real-time Operations*]

4.1. If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.

M4. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request or that it communicated denial to the Reliability Coordinator no more than 10 minutes after the denial. (R4)

R5. Each Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange under any of the following conditions: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations, Real-time Operations*]

5.1. It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.

5.2. It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition.

5.3. It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

M5. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that, under the conditions in R5.1, R5.2, or R5.3, it did not transition an Arranged Interchange to Confirmed Interchange. (R4)

R6. Each Sink Balancing Authority shall distribute all notifications of whether an Arranged Interchange was transitioned to Confirmed Interchange to the following entities, and notifications of on-time Confirmed Interchange shall be distributed such that they are delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

6.1. The Source Balancing Authority,

6.2. Each Intermediate Balancing Authority,

6.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,

6.4. Each Transmission Service Provider included in the Arranged Interchange, and

6.5. Each Purchasing Selling Entity included in the Arranged Interchange.

M6. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it distributed notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to the listed entities, and that for an on-time Confirmed Interchange, the distribution was delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D. (R6)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, R4, R5, and R6 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R3 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-day Operations, Real-time Operations	Medium	N/A	N/A	The Sink Balancing Authority did not distribute an Arranged Interchange to all of the entities listed in the requirement.	The Sink Balancing Authority did not distribute an Arranged Interchange to any of the entities listed in the requirement. OR The Sink Balancing Authority distributed an Arranged Interchange exceeding the times specified in Attachment 1 Column A that resulted in one or more of the conditions described in Requirement R1 Parts 1.1 and 1.2.
R2	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	When not subject to the provisions in Requirement R5, the Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny its transition to Confirmed Interchange prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment

						1, Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange. OR The scheduling path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange.
R3	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny its transition to Confirmed Interchange prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment

						1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
R4	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.	The Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, Column B.
R5	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	One of the conditions in Requirement 5 Parts 5.1, 5.2, or 5.3 was met, and the Sink Balancing Authority transitioned an Arranged Interchange to Confirmed Interchange.

R6	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Sink Balancing Authority did not distribute notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to all of the entities listed in Requirement R6 Parts 6.1-6.5.	The Sink Balancing Authority did not distribute notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to any of the entities listed in Requirement R6 Parts 6.1-6.5. OR The Sink Balancing Authority distributed notifications of whether an Arranged Interchange was transitioned to Confirmed Interchange, but did not distribute the notifications such that they were delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1 – Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [4] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[5]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[5]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1 minute from receipt	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1 minute from receipt	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1 minute from receipt	≤ 10 minutes from Arranged Interchange receipt	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from receipt	≤ 20 minutes from Arranged Interchange receipt	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from receipt	≤ 2 hours from Arranged Interchange receipt	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[4] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[5] Times are for software performance specifications, only.

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [6] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[7]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[7]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1 minute from receipt	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is at the top of the hour	Late	≤ 1 minute from receipt	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is not the top of the hour	Late	≤ 1 minute from receipt	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of Confirmed Interchange
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time	≤ 1 minute from receipt	≤ 5 minutes from Arranged Interchange receipt	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of the hour	On-time	≤ 1 minute from receipt	≤ 6 minutes from Arranged Interchange receipt	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start

[6] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[7] Times are for software performance specifications, only.

		A	B	C	D
If Arranged Interchange[6] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[7]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[7]**	**BA Prepares Confirmed Interchange for Implementation**
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time	$\leq$ 1 minute from receipt	$\leq$ 7 minutes from Arranged Interchange receipt	$\leq$ 1 minute from receipt of all Reliability Assessments	$\geq$ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time	$\leq$ 1 minute from receipt	$\leq$ 8 minutes from Arranged Interchange receipt	$\leq$ 1 minute from receipt of all Reliability Assessments	$\geq$ 3 minutes prior to ramp start
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time	$\leq$ 1 minute from receipt	$\leq$ 9 minutes from Arranged Interchange receipt	$\leq$ 1 minute from receipt of all Reliability Assessments	$\geq$ 3 minutes prior to ramp start
<1 hour and $\geq$ 15 minutes prior to ramp start	On-time	$\leq$ 1 minute from receipt	$\leq$ 10 minutes from Arranged Interchange receipt	$\leq$ 1 minute from receipt of all Reliability Assessments	$\geq$ 3 minutes prior to ramp start
$\geq$ 1 hour and < 4 hours prior to ramp start	On-time	$\leq$ 1 minute from receipt	< 20 minutes from Arranged interchange receipt	$\leq$ 1 minute from receipt of all Reliability Assessments	$\geq$ 39 minutes prior to ramp start
$\geq$ 4 hours prior to ramp start	On-time	$\leq$ 1 minute from receipt	$\leq$ 2 hours from Arranged Interchange receipt	$\leq$ 1 minute from receipt of all Reliability Assessments	$\geq$ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time $\geq$ 00:00 PPT of following day	On-time	$\leq$ 1 minute from receipt	By 12:00 PPT of day the Arranged Interchange was received	$\leq$ 1 minute from receipt of all Reliability Assessments	$\geq$ 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
  - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
  - All reliability entities involved in the Arranged Interchange are valid.
  - Generation source and load sink are defined.
  - Megawatt profile is defined.
  - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
  - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
  - Megawatt profile is defined.
  - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
  - Distribute notification as each entity approves or denies an Arranged Interchange.
  - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
  - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

    - Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
    - Receive distribution of Arranged Interchange
    - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
    - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
    - Submit a request to modify Interchange

- While interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
    - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
    - How to notify others that it is activating the plan
    - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
    - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
    - Delegation of approval rights and proxy actions, if such approaches will be used.
    - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
    - Personnel plans for short-term and extended periods.
    - Training of personnel in the use of the plan.

Standard Development Timeline

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Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
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Description of Current Draft

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Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	July 2013
Recirculation ballot	October 2013
BOT adoption	November 2013
File standard with regulatory authorities.	December 2013

Effective Dates

First day of the second calendar quarter beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking
0	**April 1, 2005**	**Effective Date**	**New**
1	**May 2, 2006**	**Adopted by the NERC Board of Trustees**	**Revised**
2	**TBD**	**Adopted by the NERC Board of Trustees**	**Revised under Project 2008-12**

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Dynamic Schedule: A time-varying energy transfer that is updated in real time and included in the Net Interchange Scheduled term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).

Pseudo-Tie: A time-varying energy transfer that is updated in real time and included in the Net Interchange Actual term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

Adjacent Balancing Authority - A Balancing Authority Area that is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

Confirmed Interchange - The state where the Sink Balancing Authority has verified the Arranged Interchange.

Composite Confirmed Interchange – The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.

Attaining Balancing Authority: A Balancing Authority bringing generation or load into its effective control boundaries through a dynamic transfer from the Native Balancing Authority.

Native Balancing Authority: A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a dynamic transfer.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Implementation of Interchange**
2. **Number:** **INT-009-2**
3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process and maintain the generation-to-load balance.
4. **Applicability:**

   4.1. Balancing Authority.
5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.

   The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term "Composite Confirmed Interchange" has been introduced.

   The content of INT-009-2 has been revised and expanded in the following manner:

   - R1 was modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.
   - R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Net Interchange Actual term for their ACE controls.
   - R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls an HVDC tie coordinates the Confirmed Interchange.

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and including any interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations*]

M2. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process). (R2)

R3. Each Balancing Authority in whose area the HVDC tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie if applicable. [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2 and R3 for the most recent 3 months plus the current month.

If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, excluding Dynamic Schedules and including any interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, for that hour.
R2	Real Time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process).
R3	Real Time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

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Development Steps Completed

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Version History

Version	Date	Action	Change Tracking
1	TBD		New

Definitions of Terms Used in Standard

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Request for Interchange - A collection of data as defined in the NAESB Business Practice Standards, to be submitted to the Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.

Confirmed Interchange - The state where the Sink Balancing Authority has verified the Arranged Interchange.

Reliability Adjustment Arranged Interchange - Request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

Dynamic Schedule: A time-varying energy transfer that is updated in real time and included in the Net Interchange Scheduled term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Interchange Initiation and Modification for Reliability**
2. **Number:** **INT-010-2**
3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability events.
4. **Applicability:**
   4.1. Balancing Authority
   4.2. Transmission Service Provider
   4.3. Reliability Coordinator
5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to eliminate the prerequisite that a Balancing Authority experience a loss of resources covered by an energy sharing agreement with respect to requirement applicability.
   - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.
   - R4 is created to ensure that Reliability Adjustment Arranged Interchanges are initiated only for reliability related reasons.
   - R5 was created from INT-005-3 R1.1 describing the restricted list of entities that have approval rights on a Reliability Adjustment Arranged Interchange
   - R6 was created to address the fact that when a Reliability Adjustment Arranged Interchange is approved for a Dynamic Schedule, action is required by the Balancing Authority to ensure that the data source feeding the Net Interchange value of ACE value is adjusted in accordance the MW value of the Reliability Adjustment Arranged Interchange.

B. Requirements and Measures

R1. Each Sink Balancing Authority shall ensure that a Request for Interchange is created within 60 minutes of the start of the energy sharing, and with a start time no more than 60 minutes beyond the start of the energy sharing for Interchange scheduled in duration of more than 60 minutes as part of an energy sharing agreement,. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M1. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that when it participated in energy sharing pursuant to the subject sharing agreement lasting longer than 60 minutes, it ensured that a RFI was created within 60 minutes of the start of the energy sharing, and with a start time no more than 60 minutes beyond the start of the energy sharing. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting that modification is created within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was created within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is created reflecting that Interchange schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a RFI was created reflecting that Interchange schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

R4. Each Reliability Coordinator, Balancing Authority or Transmission Service Provider that initiates a Reliability Adjustment Arranged Interchange must have experienced one or more of the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

4.1. The loss or non-performance of generation supplying the Interchange.

4.2. The loss of Load served by the Interchange.

4.3. The loss of one or more Transmission Facilities.

4.4. An actual or potential System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance.

4.5. Any real-time reliability concern related to a specific Confirmed Interchange.

M4. Each applicable entity shall have evidence such as dated and time-stamped logs, voice recordings, electronic records, or other similar evidence that when it created a Reliability Adjustment Arranged Interchange subject to this requirement, one or more of the following were true: generation supplying the Interchange was lost or did not perform; Load being served by the Interchange was lost; one or more Transmission Facilities were lost; an actual or potential SOL or IROL exceedance was experienced; or the entity experienced a real-time reliability concern related to a specific confirmed Interchange. (R4)

R5. Each Sink Balancing Authority shall distribute any Reliability Adjustment Arranged Interchange only to the Source Balancing Authority for reliability assessment. [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations*]

M5. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that it distributed any Reliability Adjustment Arranged Interchange only to the Source Balancing Authority for reliability assessment. (R5)

R6. Each Balancing Authority involved in a Reliability Adjustment Arranged Interchange involving a Dynamic Schedule shall use agreed upon values that ensure any limit established by the Reliability Adjustment Arranged Interchange is not exceeded. [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations*]

M6. The Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that following any Reliability Adjustment Arranged Interchange involving a Dynamic Schedule it used agreed upon values that ensured any limit established by the Reliability Adjustment Arranged Interchange was not exceeded. (R6)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, R3, R4, R5 and R6 for the most recent three calendar months plus the current month.
- The Reliability Coordinator and Transmission Service provider shall maintain evidence to show compliance with R4 for the most recent three calendar months plus the current month.
- If a Reliability Coordinator, Balancing Authority, or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Lower	The Sink Balancing Authority ensured that a Request for Interchange was created, and it was created more than 60 minutes, but not more than 75 minutes, following the start of the energy sharing.	The Sink Balancing Authority ensured that a Request for Interchange was created, and it was created more than 75 minutes, but not more than 90 minutes, following the start of the energy sharing.	The Sink Balancing Authority ensured that a Request for Interchange was created, and it was created more than 90 minutes, but not more than 120 minutes, following the start of the energy sharing.	The Sink Balancing Authority ensured that the Request for Interchange was created, and it was created more than 120 minutes following the start of the energy sharing. OR The Sink Balancing Authority did not ensure that a RFI was created following the start of the energy sharing.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting the modification was created within 60 minutes following the start of the modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a RFI was created within 60 minutes following the start of the scheduled Interchange.

R4	Operations Planning, Same Day Operations, Real Time Operations	Lower	N/A	N/A	N/A	The responsible entity initiated a Reliability Adjustment Arranged Interchange and did not experience one of the elements listed in Requirement R4 Parts 4.1 – 4.5.
R5	Real Time Operations	Medium	N/A	N/A	N/A	The responsible entity failed to distribute any Reliability Adjustment Arranged Interchange to the Source Balancing Authority for reliability assessment.
R6	Real Time Operations	Lower	N/A	N/A	N/A	The responsible entity failed to use an agreed upon value that ensured any limit established by the Reliability Adjustment Arranged Interchange involving a Dynamic Schedule is not exceeded

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

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Version History

Version	Date	Action	Change Tracking
1.0	TBD	Adopted by the NERC Board of Trustees	New standard developed

Definitions of Terms Used in Standard

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Request for Interchange - A collection of data as defined in the NAESB Business Practice Standards, to be submitted to the Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

NOTE: In November 2009, the Coordinate Interchange Standards Drafting Team (CISDT) posted a proposed new standard: INT-011-1—Interchange Coordination Support. That standard focused on the electronic capabilities required of entities for supporting Interchange coordination. After reviewing stakeholder comments on that posting and discussing the standard further, the CISDT determined that its contents would be better suited for the guideline and technical basis section of proposed INT-006-4. Because INT-011-1—Interchange Coordination Support never went before NERC's Board of Trustees or FERC, the CISDT is reusing the INT-011-1 number here, for INT-011-1—Intra-Balancing Authority Transaction Identification.

A. Introduction

1. **Title:** **Intra-Balancing Authority Transaction Identification**
2. **Number:** **INT-011-1**
3. **Purpose:** To ensure that transfers within a Balancing Authority Area using Point to Point Transmission Service are communicated and accounted for in congestion management procedures.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Load-Serving Entities

5. **Background:**

   This standard was created in response to a FERC directive in Order 693, paragraph 817: *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

   The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

B. Requirements and Measures

R1. Each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange unless the information about intra-Balancing Authority transfers is included in congestion

management procedure(s) via an alternate method. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations]*

M1. Each Load-Serving Entity subject to R1 shall have evidence, such as dated and time-stamped electronic records, documentation of congestion management procedures, or other similar evidence, that a Request for Interchange was submitted for each intra-Balancing Authority transfer subject to R1 or that each intra-Balancing Authority transfer subject to R1 was accounted for in congestion management procedure(s) via an alternate method. (R1)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Load-Serving Entity shall keep data or evidence to show compliance with R1 for the most recent three months plus the current month unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	*Operations Planning, Same-day Operations*	*Lower*	N/A	N/A	N/A	The Load-Serving Entity used Point to Point Transmission Service for an intra-Balancing Authority Area transfer, and did not submit a Request for Interchange for an intra-Balancing Authority transfer that is not included in congestion management procedure(s) via an alternate method.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2008-12 Coordinate Interchange Standards

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the standards. The electronic comment form must be completed by 8:00 p.m. ET **Friday, August 23, 2013**. Enter comments in simple text format. Certain characters, bullets, numbers, and special formatting will not be retained.

If you have questions please contact Steve Crutchfield or by telephone at 609-651-9455.

Project 2008-12: Coordinate Interchange Standards Project Page

Background Information

The Coordinate Interchange Standard Drafting Team posted drafts of INT-004-3, INT-006-4, INT-009-2, INT-010-2, and INT-011-1 for a 30-day public comment period from November 10, 2009 through December 11, 2009. Following the posting, the drafting team began to respond to comments and revised the standards. At about the same time, the NERC Standards Committee began an effort to reprioritize projects and to focus industry and NERC staff resources to the most important projects.

As a result, this project was placed on the inactive list for two years. In February 2013, the team was reconvened and has completed its consideration of comments from the previous posting and as well as comments concerning the INT standards from Phase 1 of the Paragraph 81 project. The team is soliciting specific additional feedback before finalizing the standards for balloting, to ensure that appropriate alternatives identified, and if necessary, a transition plan is developed for any requirements that meet Paragraph 81 criteria but are necessary for other reasons.

The following documents are posted on the project page to assist in preparing a response to the drafting team:

- The criteria developed by the Paragraph 81 drafting team
- A spreadsheet containing the comments related to the INT standards that were received during Phase 1 of Paragraph 81
- A mapping document showing the disposition of each requirement from the currently enforceable versions of the INT standards in the proposed revisions
- A summary of the revisions made to each standard since the last posting

Questions

Paragraph 81 Considerations: The Coordinate Interchange SDT (CISDT) has reviewed all of the previously posted INT standards, along with stakeholder feedback on the INT standards from Phase 1 of the Paragraph 81 project, as well as outstanding FERC directives assigned to the Coordinate Interchange project. The CISDT believes that all of the requirements remaining in the four standards that are being posted are necessary and require accountability.

Please review the mapping document and the list of Paragraph 81 recommendations provided to the INT team as a result of comments received from stakeholders during Phase 1 of Paragraph 81, along with the proposed revisions to the INT standards. If you believe that a specific requirement in the proposed INT-004-3, INT-006-4, INT-009-2, INT-010-2, or INT-011-1 could be better addressed through alternate means than a NERC Reliability Standard, please provide the specific standard and requirement number, along with a specific suggestion for an alternate means to ensure the intended action is accomplished. Some examples of alternate means could include working with NAESB to incorporate the requirement into NAESB business practice standards; moving the requirement into the Guideline and Technical Basis section of the same standard; or working with a technical committee to develop a NERC guideline.

Please be as specific as possible.

Comments:

Paragraph 81 Criteria

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

B2. Data Collection/Data Retention

These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant

The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)

Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?

The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?

The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?

The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 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.

Principle 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.

Principle 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.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT	all	Georgia Sys Ops Corp	x		x			x				Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Note: INT-007-1 R1.2 is part of Initial Phase.	x				
INT	all	City of Austin						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, we recommend that the Standards Drafting Team retire the INT Reliability Standards and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x	x		x	
INT-001-3	R1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-001-3	R1.1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-001-3	R2.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-001-3	R2.1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-001-3	R2.2.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-003-3	R1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-003-3	R1.1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-003-3	R1.1.1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-003-3	R1.1.2.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-003-3	R1.2.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-004-2	R1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-004-2	R2.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-004-2	R2.1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-004-2	R2.2.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-004-2	R2.3.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-005-3	R1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-005-3	R1.1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-006-3	R1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-006-3	R1.1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-006-3	R1.1.1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-006-3	R1.1.2.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-006-3	R1.1.3.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-006-3	R1.2.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-007-1	R1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-007-1	R1.1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-007-1	R1.2.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-007-1	R1.3.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-007-1	R1.3.1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-007-1	R1.3.2.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-007-1	R1.3.3.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-007-1	R1.3.4.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-007-1	R1.4.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-008-3	R1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-008-3	R1.1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-008-3	R1.1.1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-008-3	R1.1.2.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-009-1	R1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-010-1	R1.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-010-1	R2.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-010-1	R3.	Occidental Energy Ventures						X	X		X	OEVC has only addressed the Requirements where OEVC has additional comments to what the Trades have provided.In addition, OEVC believes the following requirements can also be removed:	x				
INT-001-3	R1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-001-3	R1.1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-001-3	R2.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-001-3	R2.1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-001-3	R2.2.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-003-3	R1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-003-3	R1.1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-003-3	R1.1.1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-003-3	R1.1.2.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	

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INT-003-3	R1.2.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-004-2	R1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-004-2	R2.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-004-2	R2.1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-004-2	R2.2.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-004-2	R2.3.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-005-3	R1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-005-3	R1.1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-006-3	R1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-006-3	R1.1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-006-3	R1.1.1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-006-3	R1.1.2.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-006-3	R1.1.3.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-006-3	R1.2.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-007-1	R1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-007-1	R1.1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-007-1	R1.3.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-007-1	R1.3.1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-007-1	R1.3.2.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-007-1	R1.3.3.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-007-1	R1.3.4.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-007-1	R1.4.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-008-3	R1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-008-3	R1.1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-008-3	R1.1.1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-008-3	R1.1.2.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-009-1	R1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-010-1	R1.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-010-1	R2.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-010-1	R3.	EEI						x	x		x	Many of the INT Reliability Standard requirements are very close to duplicative of similar requirements in the BAL Reliability Standards or address commercial matters. As drafted, the INT Reliability Standards include tasks or activities that do little, if anything, to promote the protection the Bulk Electric System. Thus, it is recommended that the Standards Drafting Team retire the INT Reliability Standards, and, as necessary, transfer any requirement that protect reliability to the BAL Reliability Standards.	x			x	
INT-004-2	R1.	ACES Power Mktg									x	INT-004-2 R1 has nothing to do with reliability and should be included in the list of retirements. Failing to reload an Interchange Transaction that was curtailed for a reliability event has no reliability impact. It is a remnant from the NERC Policies that was added at the request of market participants because once transactions were cut, reliability entities did not always allow the transaction to resume once the reliability issue had been addressed. This is strictly a commercial issue.	x				
INT-001-3	R1.	Occidental Power Services, Inc.						x			x	This requirement is at best a business practice of markets (protocol). These schedules can be rejected if not correctly submitted, can be cut if not executed correctly, and the PSE can be penalized if there are offenses. Remove PSE from R1 and applicability section.		x			x

Std	Req	Company	Criteria									Full Text	retire	modify	clarify	combine	eliminate application
			B1	B2	B3	B4	B5	B6	B7	B8	B9						
INT-004-2	R2.	Occidental Power Services, Inc.						x			x	This requirement is at best a business practice of markets (protocol). These schedules can be rejected if not correctly submitted, can be cut if not executed correctly, and the PSE can be penalized if there are offenses. Remove PSE from R2 and applicability section.		x			x
INT-004-2	R2.1.	Occidental Power Services, Inc.						x			x	This requirement is at best a business practice of markets (protocol). These schedules can be rejected if not correctly submitted, can be cut if not executed correctly, and the PSE can be penalized if there are offenses. Remove PSE from R2 and applicability section.		x			x
INT-004-2	R2.2.	Occidental Power Services, Inc.						x			x	This requirement is at best a business practice of markets (protocol). These schedules can be rejected if not correctly submitted, can be cut if not executed correctly, and the PSE can be penalized if there are offenses. Remove PSE from R2 and applicability section.		x			x
INT-004-2	R2.3.	Occidental Power Services, Inc.						x			x	This requirement is at best a business practice of markets (protocol). These schedules can be rejected if not correctly submitted, can be cut if not executed correctly, and the PSE can be penalized if there are offenses. Remove PSE from R2 and applicability section.	x				x

Project 2008-12 - Coordinate Interchange Standards

Mapping Document

Project Purpose

The purpose of Project 2008-12 is to revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange. The drafting team also addressed the Interchange Subcommittee concerns related to the dynamic Transfers and Pseudo-ties and addressed previously identified stakeholder comments and applicable directives from Order 693. These issues and directives include defining communications on reloading interchange transactions due to different operational conditions and to bringing the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for: **R1.1.** All Dynamic Schedules at the expected average MW profile for each hour.	Revised and Moved into INT-004-3	**INT-004-3:** R1. Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie at either: [Violation Risk Factor: Lower] [Time Horizon:

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Operations Planning, Same-day Operations] • The expected average MW profile for each hour if a forecast for the Dynamic Schedule or Pseudo-Tie is available, or • The expected maximum MW profile for each hour if no forecast for the Dynamic Schedule or Pseudo-Tie is available.
R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority: **R2.1.** If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator. **R2.2.** For each bilateral Inadvertent Interchange payback.	Retired	The CI SDT believes that this requirement is no longer necessary for reliability. Since the proposed INT-009-2 R2 makes is clear that the Net Scheduled Interchange term in the control equation can only include Confirmed Interchange as agreed to between Balancing Authorities and metered values for Dynamic Schedules, this by definition requires that an Arranged Interchange be created in order to implement the schedules listed in R2.1 and R2.2. From a reliability perspective, it is unimportant who creates these Arranged interchanges – only that they be created and confirmed prior to being entered into the control equation.

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. **R1.1.** The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including: **R1.1.1.** Interchange Schedule start and end time. **R1.1.2.** Energy profile. **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.	Revised and Moved into INT-009-2	**INT-009-2:** R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign to that of the Adjacent Balancing Authority. R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process). [Violation Risk Factor: Medium] [Time Horizon: Real Time

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Operations] R3. Each Balancing Authority in whose area the HVDC tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie if applicable. [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations, Operations Planning]

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.	Retired	The CI SDT believes that at a minimum, this requirement does not belong in the "Dynamic Schedules" standard. However, for several reasons, the CI SDT further believes that this specific requirement is no longer required: • It mandates a practice (releasing of E-Tag limits) that is process related. • The practice is already addressed in related NAESB standards (WEQ-004 Appendix B - E-Tag Actions). • Use of a limit (and the associated release of that limit) is only one particular way to address curtailments. Other ways exist that could be used in lieu of this approach. The reliability standard should not mandate a single approach when others may suffice.
R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs:	Revised	R2. Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is reviewed and

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R2.1. The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +10%. **R2.2.** The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +25 megawatt-hours. **R2.3.** A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.		updated if needed for the next available scheduling hour and future hours if any one of the following occurs: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same Day Operations, Real Time Operations] 2.1. For Confirmed Interchange using the expected average MW profile, if the average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile for the next hour indicated in the Confirmed Interchange by more than 10%. 2.1.1. The Load-Serving Entity shall ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours if the review performed in R2 indicates that a deviation of more than 10% will persist. 2.2. For Confirmed Interchange using the expected average MW profile, if the average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated in the Confirmed Interchange by more than 25 MW and this deviation is

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		expected to continue in future hours. 2.2.1. The Load-Serving Entity shall ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours if the review performed in R2 indicates that a deviation of more than 25 MW will persist. 2.3. Receipt of notification from a Reliability Coordinator or Transmission Operator that a deviation from the hourly energy profile indicated in the Confirmed Interchange, regardless of magnitude, is a reliability concern and requires that the Confirmed Interchange be updated.

Standard: INT-005-3, Interchange Authority Distributes Arranged Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange. **R1.1.** When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority.	Revised and moved into INT-006-4	**INT-006-4:** R1. Each Sink Balancing Authority shall distribute each Arranged Interchange to the Source Balancing Authority, each Intermediate Balancing Authority, and each Transmission Service Provider included in the Arranged Interchange so that these entities can conduct a reliability assessment of the Arranged Interchange before the Arranged Interchange is implemented. When distributing Arranged Interchange, each Sink Balancing Authority shall ensure that each distribution exceeding the times specified in Attachment 1, Column A, does not result in either of the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 1.1. On-time Arranged Interchange where not all Balancing Authorities and Transmission Service Providers either approved or denied as specified in R2, R3, and R4.

Standard: INT-005-3, Interchange Authority Distributes Arranged Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2. On-time Arranged Interchange being transitioned to Confirmed Interchange without enough time to incorporate into scheduling systems prior to ramp start as specified in Attachment 1, Column D.

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange. **R1.1.** Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to: **R1.1.1.** Energy profile (ability to support the magnitude of the Interchange). **R1.1.2.** Ramp (ability of generation maneuverability to accommodate). **R1.1.3.** Scheduling path (proper connectivity of Adjacent Balancing Authorities). **R1.2.** Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the	Revised	R2. With the exception of the provisions in R5, each Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange shall approve or deny its transition to Confirmed Interchange prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 2.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange. 2.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the scheduling path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated.		R3. Each Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange, shall approve or deny its transition to Confirmed Interchange prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 3.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following: **R1.1.** Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate). **R1.2.** All reliability entities involved in the Arranged Interchange are currently in the NERC registry. **R1.3.** The following are defined: **R1.3.1.** Generation source and load sink. **R1.3.2.** Megawatt profile. **R1.3.3.** Ramp start and stop times. **R1.3.4.** Interchange duration. **R1.4.** Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.	Revised and moved into INT-006-4	R1.1, R1.2 and R1.3 ensure the data submitted on the interchange is valid. This activity occurs in software validation and is not appropriate for a reliability standard; these items are included in the Technical Basis and Guidelines section of INT-006. Interchange that does not meet these criteria would not be an Arranged Interchange. R1.4 . is addressed in a INT-006, R5. If the Arranged Interchange does not fall under any of the criteria in this new requirement, it would be transitioned from Arranged Interchange to Confirmed Interchange. R5. Each Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange under any of the following conditions: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 5.1. It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition. 5.2. It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition. 5.3. It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

Standard: INT-008-3, Interchange Authority Distributes Status		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange. **R1.1.** For Confirmed Interchange, the Interchange Authority shall also communicate: **R1.1.1.** Start and stop times, ramps, and megawatt profile to Balancing Authorities. **R1.1.2.** Necessary Interchange information to NERC-identified reliability analysis services.	Revised and moved into INT-006-4	**INT-006-4:** R6. Each Sink Balancing Authority shall distribute all notifications of whether an Arranged Interchange was transitioned to Confirmed Interchange to the following entities, and notifications of on-time Confirmed Interchange shall be distributed such that they are delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 6.1. The Source Balancing Authority, 6.2. Each Intermediate Balancing Authority, 6.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange, 6.4. Each Transmission Service Provider included in the Arranged Interchange, and 6.5. Each Purchasing Selling Entity included in the Arranged Interchange.

Standard: INT-009-1, Implementation of Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.	Revised	**R1.** Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign to that of the Adjacent Balancing Authority.

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required.	Revised	**INT-010-2:** **R1.** Each Sink Balancing Authority shall ensure that a Request for Interchange is created within 60 minutes of the start of the energy sharing, and with a start time no more than 60 minutes beyond the start of the energy sharing for Interchange scheduled in duration of more than 60 minutes as part of an energy sharing agreement,. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations]
R2. For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event.	Revised	**INT-010-2:** **R2.** Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting that modification is created within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [Violation Risk Factor: Lower]

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		[Time Horizon: Real Time Operations]
R3. For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event.	Revised	**INT-010-2:** **R3.** Each Sink Balancing Authority shall ensure that a Request for Interchange is created reflecting that Interchange schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations] **R4.** Each Reliability Coordinator, Balancing Authority or Transmission Service Provider that initiates a Reliability Adjustment Arranged Interchange must have experienced one or more of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same Day Operations, Real Time Operations] 4.1. The loss or non-performance of generation supplying the Interchange. 4.2. The loss of Load served by the Interchange.

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		4.3. The loss of one or more Transmission Facilities. 4.4. An actual or potential System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance. 4.5. Any real-time reliability concern related to a specific Confirmed Interchange.

Project 2008-12 Coordinate Interchange Standards

Summary of Revisions Made to Standards Posted in September 2010

INT-004-3 — Dynamic Transfers

1. Revised Purpose Statement: "To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management tools [for example: the NERC Interchange Distribution Calculator (IDC), the WECC Security Analysis System (SAS)]."
   a. Previous version was: "To ensure Dynamic Schedules are communicated and accounted for appropriately in reliability procedures."
2. Applicability: Removed Reliability Coordinator and Transmission Operator and replaced Purchasing-Selling Entity with Load Serving Entity. The latter provides more specificity.
3. Added Background Section
4. Requirement R1 was revised to replace PSE with Load Serving Entity.
5. Requirement R2 was revised to clarify the trigger for review and the trigger for updating the Interchange for a future time period.
6. Requirements R3 and R4 are created to address the coordination that must occur between all entities involved prior to the initial implementation of a Pseudo-Tie. Requirement R3 is to be implemented until the NAESB registry is able to accept Pseudo-Tie registrations. Requirement R4 is to be implemented when the NAESB registry is able to accept Pseudo-Tie registrations. Until such time, R3 will be in effect.
7. Added Guidelines and Technical Basis Section summarizing the concepts to be considered when establishing Dynamic Transfers.

INT-006-4 — Evaluation of Interchange Transactions

1. Revised Purpose Statement: To ensure that entities conduct a reliability assessment of each Arranged Interchange before it is implemented. The previous purpose statement was: "To ensure that each Arranged Interchange is checked for reliability before it is implemented."
2. Added Background section.
3. References to specific timing (e.g., within one minute) were modified to refer to the action that needs to be accommodated. (e.g., "so that the entity can…" or "in time to…").
4. Former Requirements R5 and R6 were determined to be redundant and were combined into a new Requirement R5. Former Requirements R8 and R9, which were assigned to the Transmission Operator and the Reliability Coordinator, respectively, were deleted.

5. Updated Attachment 1 timing tables for WECC to address scheduling on a 15 minute basis.
6. Added VRFs, Time Horizons, Measures, VSL and other compliance elements (section C).
7. Added guideline and technical basis section that incorporates the required electronic capability for supporting Interchange coordination. These capabilities were originally outlined in a proposed new standard.

INT-009-2 — Implementation of Interchange

1. Purpose Statement was revised by removing the word “exactly” from prior version.
2. Added Background Section
3. Requirement R1 was revised by removing part 1.1 and re-wording the main part of the requirement to include the defined term Composite Confirmed Interchange.
4. Requirement R2 was removed (redundancy with BAL standard).
5. Added new Requirement R2 regarding Attaining and Native Balancing Authorities using a dynamic value emanating from an agreed to source for Pseudo-Ties.
6. Added Requirement R3 requiring coordination with HVDC Transmission Operators.
7. Added VRFs, Time Horizons, Measures, VSL and other compliance elements (section C).

INT-010-2 — Interchange Initiation and Modification for Reliability

1. Revised Purpose Statement: “To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability events.”
    a. Previous version was: “Allow certain types of Interchange schedules to be initiated or modified by reliability entities, and to be exempt from compliance with other Interchange Standards under abnormal operating conditions.”
2. Added Background Section
3. Requirement R1 was modified to eliminate the prerequisite that a Balancing Authority experience a loss of resources covered by an energy sharing agreement with respect to requirement applicability. Instead, R1 now applies to any balancing Authority that schedules Interchange in duration of more than 60 minutes as part of an energy sharing agreement.
4. Requirements R2 and R3 were modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.
5. Requirement R4 was created to ensure that Reliability Adjustment Arranged Interchanges are initiated only for reliability related reasons.

6. Requirement R5 was created from INT-005-3 Requirement R1, part 1.1 describing the restricted list of entities that have approval rights on a Reliability Adjustment Arranged Interchange
7. Requirement R6 was created to address the fact that when a Reliability Adjustment Arranged Interchange is approved for a Dynamic Schedule, action is required by the Balancing Authority to ensure that the data source feeding the Net Interchange value of ACE value is adjusted in accordance the MW value of the Reliability Adjustment Arranged Interchange.
8. Added VRFs, Time Horizons, Measures, VSL and other compliance elements (section C).

INT-011-1 — Intra-Balancing Authority Transaction Identification

1. Moved all previously posted requirements to the Guidelines and Technical Basis Section of INT-006-4. The CISDT believed that these requirements were good utility practices that fell short of the level of a reliability requirement.
2. Added Background Section.
3. Added a new requirement to address the FERC directive in Order No. 693 regarding the treatment of non-firm point-to-point service used for intra-balancing authority transfers.

Proposed Revisions or Additions to NERC Glossary of Terms

1. Proposed revisions to approved NERC Glossary terms:
   a. **Adjacent Balancing Authority:** A Balancing Authority Area that is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

      Existing definition: A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

   b. **Intermediate Balancing Authority:** A Balancing Authority involved in an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority**.**

      Existing Definition: A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.

   c. **Dynamic Schedule:** A time-varying energy transfer that is updated in real time and included in the Net Interchange Scheduled term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).

      Existing definition: A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.

d. **Pseudo-tie:** A time-varying energy transfer that is updated in real time and included in the Net Interchange Actual term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

   Existing definition: A telemetered reading or value that is updated in real time and used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.

e. **Request for Interchange (RFI):** A collection of data as defined in the NAESB Business Practice Standards, to be submitted to the Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.

   Existing definition: A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.

f. **Arranged Interchange:** The state where the Sink Balancing Authority has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).

   Existing definition: The state where the Interchange Authority has received the Interchange information (initial or revised).

g. **Confirmed Interchange:** The state where the Sink Balancing Authority has verified the Arranged Interchange.

   Existing definition: The state where the Interchange Authority has verified the Arranged Interchange.

h. **Sink Balancing Authority:** The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule.

   Existing Definition: The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)

i. **Source Balancing Authority:** The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for the resulting Interchange Schedule.

   Existing Definition: The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)

2. Proposed new NERC Glossary terms:

   Composite Confirmed Interchange – The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.

   Attaining Balancing Authority - A Balancing Authority bringing generation or load into its effective control boundaries through a dynamic transfer from the Native Balancing Authority.

   Native Balancing Authority - A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a dynamic transfer.

   Reliability Adjustment Arranged Interchange - Request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

3. Additional terms revised to address FERC directives:

   The CISDT had previously posted proposed requirements to address FERC Order 693, Paragraph 866. These proposed Transmission Operator and Reliability Coordinator requirements related to review of Confirmed Interchange prior to implementation. The CISDT received feedback from stakeholders as well the NERC Operating Committee that the proposed requirements were not necessary as this review was already addressed in other standards. The CISDT reviewed those standards and Interchange is not explicitly noted. The team feels that additional revisions are necessary to meet the directive. Rather than revise requirements, the CISDT is proposing revisions to a defined term as it applies to existing standards. The term is Operational Planning Analysis:

   > Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

   This defined term is used in existing IRO-008-1 (Reliability Coordinator Operational Analyses and Real-time Assessments) and proposed TOP-002-3 (Operations Planning). In IRO-008-1, Requirement R1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider interchange when performing the study. When the results indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3. TOP-002-3 contains a requirement for the Transmission Operator to perform an Operational Planning Analysis (R1), develop plans for reliable operations based on the results of the Operational Planning Analysis and to notify other entities as to their role in those plans (R3).

A. Introduction

1. **Title: Interchange Information**
2. **Number:** INT-001-3
3. **Purpose:** To ensure that Interchange information is submitted to the NERC-identified reliability analysis service.
4. **Applicability:**

   4.1. Purchase-Selling Entities.

   4.2. Balancing Authorities.
5. **Effective Date:** August 27, 2008 (U.S.)

   NERC Board Approved: October 9, 2007

B. Requirements

R1. The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:

R1.1. All Dynamic Schedules at the expected average MW profile for each hour.

R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:

R2.1. If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.

R2.2. For each bilateral Inadvertent Interchange payback.

C. Measures

M1. The Purchasing-Selling Entity that serves the load shall have and provide upon request evidence that could include but is not limited to, its 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 Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour as specified in Requirement 1.

M2. Each Sink 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 Arranged Interchange was submitted to the Interchange Authority as specified in Requirements 2.1 and 2.2.

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

The Purchasing-Selling Entity that serves load and Sink Balancing Authority shall each 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. Levels of Non-Compliance for Sink Balancing Authorities:

2.1. Level 1: One instance of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and R2.2.

2.2. Level 2: Two instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

2.3. Level 3: Three instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

2.4. Level 4: Four or more instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

3. Levels of Non-Compliance for Purchasing-Selling Entities that Serve Load:

3.1. Level 1: One instance of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.2. Level 2: Two instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.3. Level 3: Three instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.4. Level 4: Four or more instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

E. Regional Differences

1. MISO Energy Flow Information Waiver effective on 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	October 9, 2007	Adopted by Board of Trustees (Remove WECC Waiver)	Revised
3	July 21, 2008	Regulatory Approval (Remove WECC Waiver)	Revised

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard INT-001-3 — Interchange Information

United States

Standard	Requirement	Enforcement Date	Inactive Date
INT-001-3	All	08/27/2008	

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	November 5, 2009	Added approved VRFs and VSLs to document. Removed MISO Scheduling Agent Waiver, and MISO Enhanced Scheduling Agent Waiver (Project 2009-18).	Revised
3	November 5, 2009	Approved by the Board of Trustees	
3	January 6, 2011	Approved by FERC	

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Enforcement Dates: Standard INT-003-3 — Interchange Transaction Implementation

United States

Standard	Requirement	Enforcement Date	Inactive Date
INT-003-3	All	04/01/2011	

A. Introduction

1. **Title:** **Interchange Authority Distributes Arranged Interchange**

2. **Number:** INT-005-3

3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is distributed by an Interchange Authority such that Interchange information is available for reliability assessments.

4. **Applicability:**

   4.1. Interchange Authority.

5. **Effective Date:** July 1, 2010

B. Requirements

R1. Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange.

R1.1. When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall be able to provide evidence that it has distributed the Arranged Interchange information to all reliability entities involved in the Interchange within the applicable time frame.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

1.3. Data Retention

The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a specific complaint of failure to perform R1. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate the Interchange Authority's distribution of all Arranged Interchange information to all reliability entities involved in an Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Interchange Authority.

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate that the Interchange Authority distributed the Arranged Interchange information to all reliability entities involved in that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not distributing information to all involved reliability entities as described in R1.

2.2. Level 2: Two occurrences[1] of not distributing information to all involved reliability entities as described in R1.

2.3. Level 3: Three occurrences[1] of not distributing information to all involved reliability entities as described in R1.

2.4. Level 4: Four or more occurrences[1] of not distributing information to all involved reliability entities as described in R1 or no evidence provided.

E. Regional Differences

None

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised
3	April 8, 2010	Approved by FERC, Effective July 1, 2010	

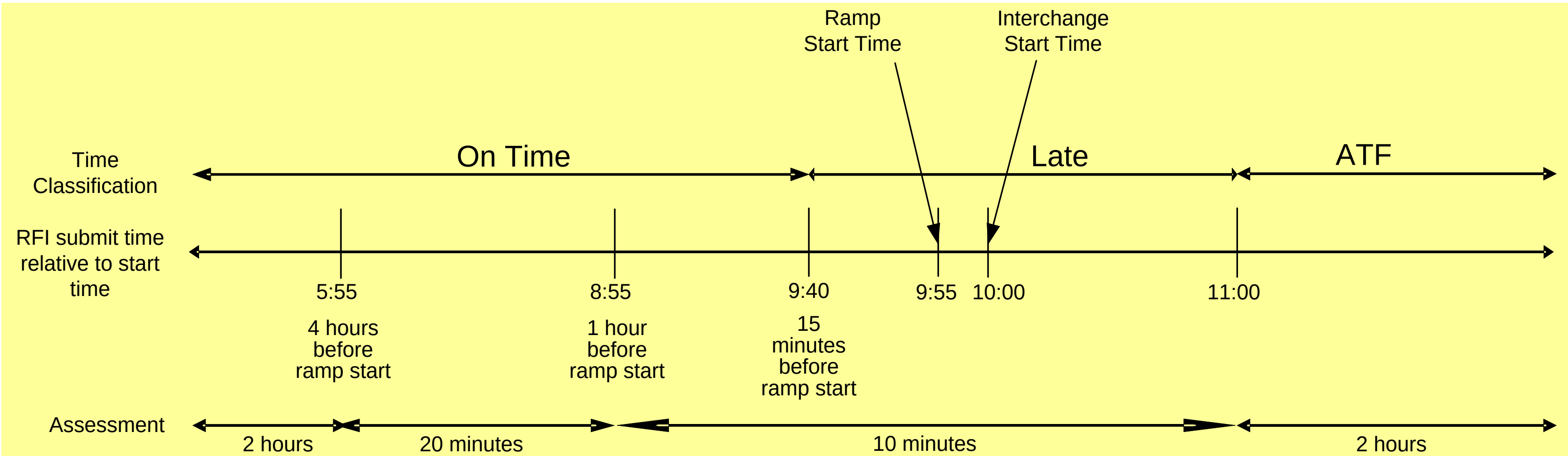
[1] This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange (RFI)[2] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the RFI start time	ATF	≤ 1 minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
<15 minutes prior to ramp start and ≤1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[2] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC

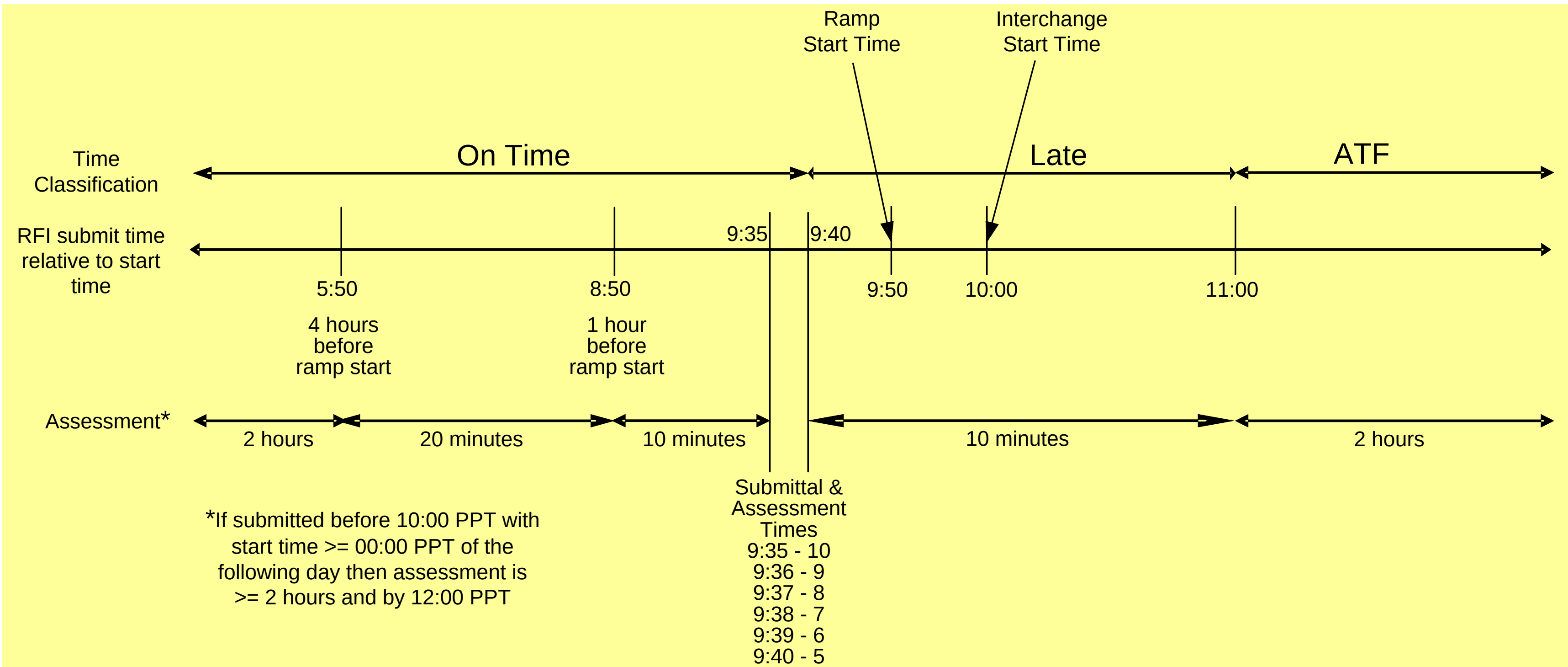


Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange (RFI)[3] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
10 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 6 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
12 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 7 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 8 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 9 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1hour and < 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	< 20 minutes from Arranged interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time	≤ 1minute from RFI submission	By 12:00 PPT of day the Arranged Interchange was received by the IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC



*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard INT-005-3 — Interchange Authority Distributes Arranged Interchange

United States

Standard	Requirement	Enforcement Date	Inactive Date
INT-005-3	All	07/01/2010	

A. Introduction

1. **Title:** **Interchange Confirmation**

2. **Number:** **INT-007-1**

3. **Purpose:** To ensure that each Arranged Interchange is checked for reliability before it is implemented.

4. **Applicability**

   4.1. Interchange Authority.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following:

R1.1. Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).

R1.2. All reliability entities involved in the Arranged Interchange are currently in the NERC registry. (Retirement approved by FERC effective January 21, 2014.)

R1.3. The following are defined:

R1.3.1. Generation source and load sink.

R1.3.2. Megawatt profile.

R1.3.3. Ramp start and stop times.

R1.3.4. Interchange duration.

R1.4. Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall show evidence that it has verified the Arranged Interchange information prior to the dissemination of the Confirmed Interchange.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.

   1.3. Data Retention

   The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate an Interchange Authority's verification that all Arranged Interchange was balanced and valid as defined in R1. The Compliance Monitor may request up to a three-month period of historical data ending with the date the request is received by the Interchange Authority.

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate an Interchange Authority's verification that an Arranged Interchange was balanced and valid as defined in R1 for that specific Interchange

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] where Interchange-related data was not verified as defined in R1.

2.2. Level 2: Two occurrences where Interchange-related data was not verified as defined in R1.

2.3. Level 3: Three occurrences where Interchange-related data was not verified as defined in R1.

2.4. Level 4: Four or more occurrences where Interchange-related data was not verified as defined in R1.

E. Regional Differences

None

[1] This does not include instances of not verifying due to extenuating circumstances approved by the Compliance Monitor.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Adopted by the NERC Board of Trustees	
1	March 16, 2007	FERC Approved	
1	February 7, 2013	R1.2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
1	November 21, 2013	R1.2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard INT-007-1 — Interchange Confirmation

United States

Standard	Requirement	Enforcement Date	Inactive Date
INT-007-1	R1.	06/18/2007	
INT-007-1	R1.1.	06/18/2007	
INT-007-1	R1.2.	06/18/2007	01/21/2014
INT-007-1	R1.3.	06/18/2007	
INT-007-1	R1.3.1.	06/18/2007	
INT-007-1	R1.3.2.	06/18/2007	
INT-007-1	R1.3.3.	06/18/2007	
INT-007-1	R1.3.4.	06/18/2007	
INT-007-1	R1.4.	06/18/2007	

A. Introduction

1. **Title:** **Interchange Authority Distributes Status**

2. **Number:** INT-008-3

3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority.

4. **Applicability:**

   4.1. Interchange Authority.

5. **Effective Date:** July 1, 2010

B. Requirements

R1. Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange.

R1.1. For Confirmed Interchange, the Interchange Authority shall also communicate:

R1.1.1. Start and stop times, ramps, and megawatt profile to Balancing Authorities.

R1.1.2. Necessary Interchange information to NERC-identified reliability analysis services.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall provide evidence that it has distributed the final status and Confirmed Interchange information specified in Requirement 1 to all Balancing Authorities, Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange within the time period defined in the Timing Table, Column C. If denied, the Interchange Authority shall tell all involved parties that approval has been denied.

M1.1 For each Arranged Interchange that includes a direct current tie, the Interchange Authority shall provide evidence that it has communicated the final status to the Balancing Authorities on both sides of the direct current tie, even if the Balancing Authorities are neither the Source nor Sink for the Interchange.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last non-compliance to R1.

1.3. Data Retention

The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance will be:

1.4.1 Verified by audit at least once every three years.

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1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate the Interchange Authority's distribution of all Arranged Interchange final status and Confirmed Interchange information to all entities involved in an Interchange per R1. The Compliance Monitor may request up to a three-month period of historical data ending with the date the request is received by the Interchange Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate that the Interchange Authority distributed the Arranged Interchange final status and Confirmed Interchange information to all entities involved in that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not distributing final status and information as described in R1.

2.2. Level 2: Two occurrences[1] of not distributing final status and information as described in R1.

2.3. Level 3: Three occurrences[1] of not distributing final status and information as described in R1.

[1] This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.

2.4. Level 4: Four or more occurrences[1] of not distributing final status and information as described in R1 or no evidence provided.

E. **Regional Differences**

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised
3	April 8, 2010	Approved by FERC, Effective July 1, 2010	

Timing Requirements for all Interconnections except WECC

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If Arranged Interchange (RFI)[2] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
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<15 minutes prior to ramp start and ≤1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
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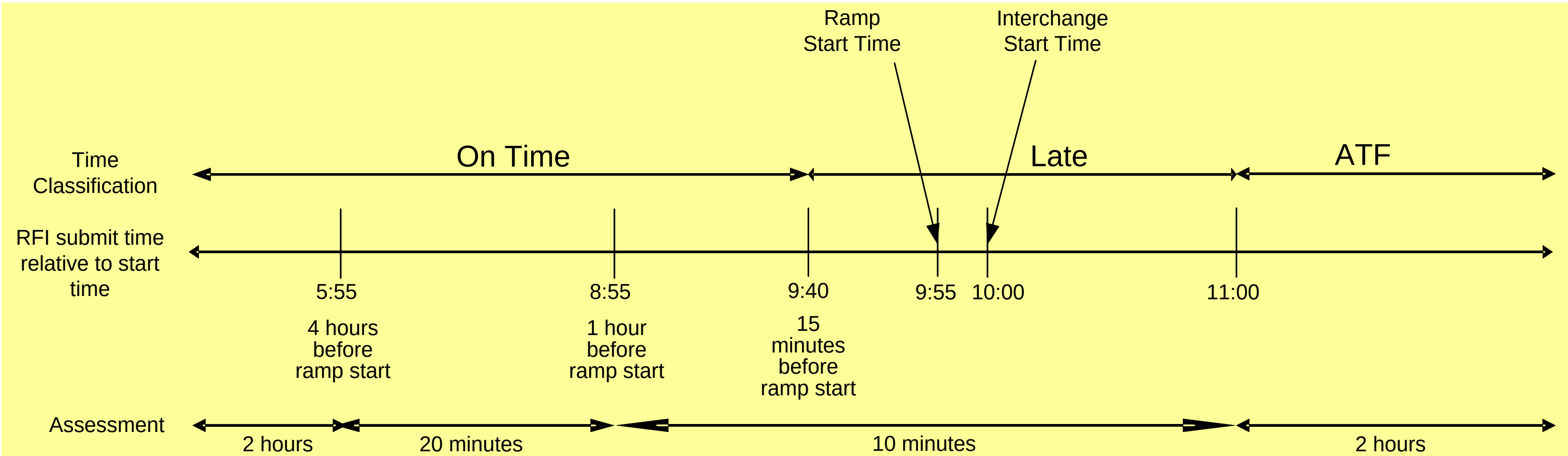
[2] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC



Timing Requirements for WECC

		A	B	C	D
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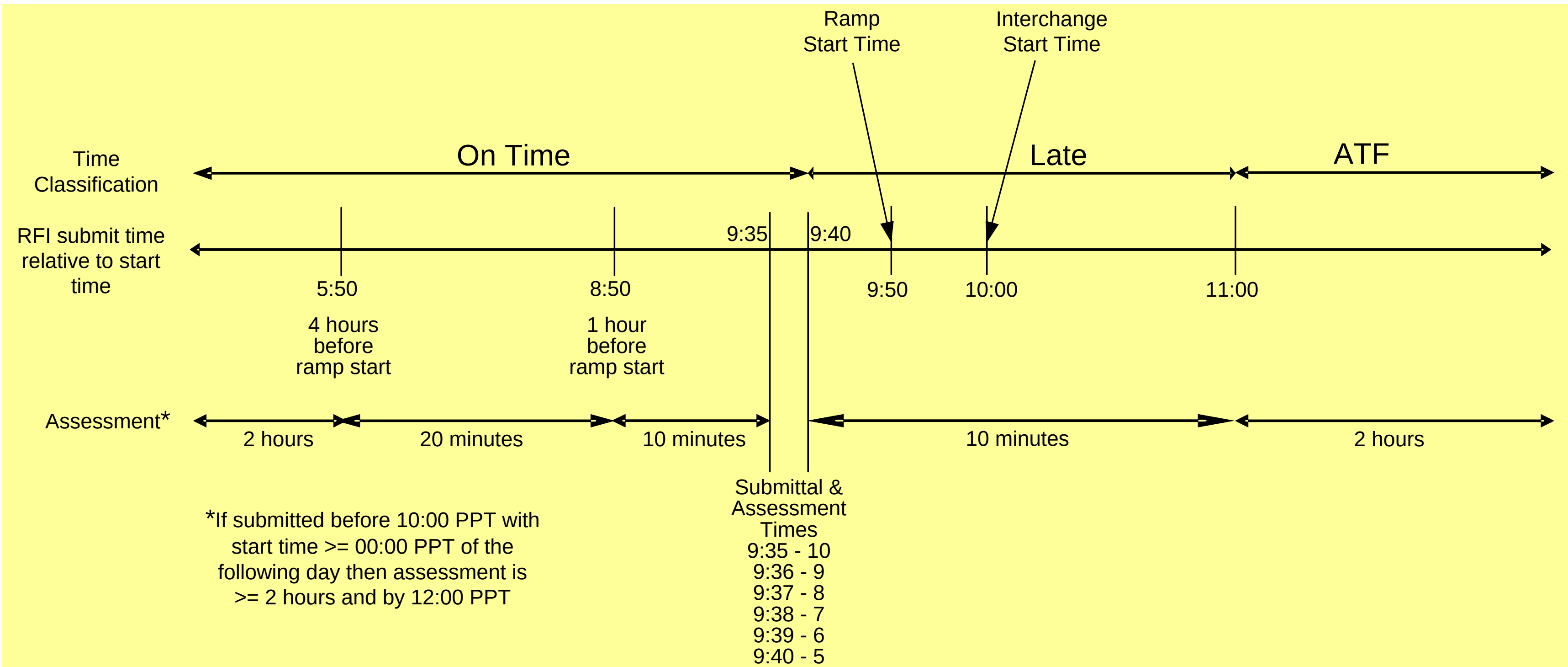
[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC



*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard INT-008-3 — Interchange Authority Distributes Status

United States

Standard	Requirement	Enforcement Date	Inactive Date
INT-008-3	All	07/01/2010	

Standards Announcement

Project 2008-12 Coordinate Interchange Standards

Comment Period: July 25, 2013 – August 23, 2013

Now Available

A 30-day informal comment period for **Project 2008-12-Coordinate Interchange Standards** is open through **8 p.m. Eastern on Friday, August 23, 2013**. The Coordinate Interchange Standard Drafting Team (CISDT) is seeking additional input on the appropriate disposition of requirements in the current approved INT standards that were identified by stakeholders as candidates for consideration under criteria developed by the Paragraph 81 drafting team. This input will assist the team in finalizing revisions to the standards prior to posting for a formal 45-day comment period and initial ballot. The proposed draft INT standards, a mapping document showing the proposed disposition of requirements from the current approved standards as well as a summary of the proposed revisions, a list of comments received on the INT standards during Phase 1 of Paragraph 81, and the additional supporting documents are posted for information.

Background information, including other supporting documents for this project, can be found on the project page. The latest draft of the team's revisions to the INT standards, a mapping document showing the proposed disposition of requirements from the current approved standards as well as a summary of the proposed revisions and a list of comments received on the INT standards during Phase 1 of Paragraph 81 are posted to assist stakeholders in preparing comments to assist the team in developing revisions that are consistent with stakeholder intent. Please contact Stephen Crutchfield, the standards developer, or a member of the CISDT if you would like additional information.

Instructions for Commenting

An informal comment period is open through **8 p.m. Eastern on Friday, August 23, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

The drafting team will consider the comments and prepare a final set of standards, implementation plan, justification for VRFs and VSLs, and other supporting documents, and submit them to be posted for a 45-day comment period and initial ballot.

Standards Development Process

The Standard Processes Manual 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 Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Individual or group. (29 Responses)
Name (17 Responses)
Organization (17 Responses)
Group Name (12 Responses)
Lead Contact (12 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (4 Responses)
Comments (29 Responses)
Question 1 (0 Responses)
Question 1 Comments (25 Responses)

Group
MRO NERC Standards Review Forum (NSRF)
Russel Mountjoy
The NSRF wishes to thank the CISDT and recommend the following recommendations: Tagging of Pseudo-Ties (INT-004 and INT-009) We do not agree that Pseudo-Ties need to be tagged, because the asset generator defines the reliability impact, and the allocation (tagging discussion) only deals with allocation of energy which is a business practice. The references to Pseudo-Ties should be removed from INT-004 R1-R4 and INT-009 R1-R2. INT-006 At a minimum, R1 and R6 are the best candidates for removal, though all of INT-006 could be removed. To operate reliably, an entity needs only a net interchange with its neighbor. The details of what customer transactions make up that net interchange is commercial/financial. These requirements represent the functions and actions necessary to effectively manage the details of interchange data. If this information were located in a NAESB Business Practice Standards and the NAESB Electronic Tagging Functional Specification, which are the source of the software specifications, and is open to the industry for comment and voting, that would be adequate. INT-009 BAL-005 R9-R12 could be modified to be clearer and incorporate the language/intent of these requirements. Thus, this Standard would no longer be necessary. When specifically reviewing R3, although this requirement has been present since the original policy language was converted to standards; it is an obvious function that is required in order for the flow to be set as desired. This is comparable to generators needing to be told where to operate but there is no requirement for ‘who’ to notify them. INT-010 R1-R3 are administrative to ‘document’ the flow after-the-fact. Real Time has already passed so it is not necessary for reliability. It is good practice to do these activities but they should be documented in best practices outside of the requirements. R4 is simply trying to enforce that entities don’t use the ‘expedited’ approval process for non-reliability reasons. A description in NAESB business practices would be adequate. R5 may have some reliability value in that we desire an expedited process to have a curtailment approved.
Group
Northeast Power Coordinating Council

Guy Zito
In general, these Standards represent the functions and actions necessary to effectively manage the details of interchange data. If this information were located in NAESB Business Practice Standards, which are the sources of the software specifications, and open to the industry for comment and voting, that would be adequate to serve reliability needs. Comments by each individual Standard: INT-004 For those entities that utilize dynamic transfers the transparency that the requirements provide is necessary for reliability. INT-006 Requirements R1 and R6 can be removed (assuming the Standard is not retired) because they deal with given concepts of Arranged Interchange. INT-009 BAL-005 Requirements R9 through R12 could be revised to incorporate the language/intent of these INT requirements. INT-009 would no longer be necessary. Regarding INT-009 R3, even though this requirement has been present since the original policy language was converted to Standards, it is an obvious function that is required in order for the flow to be set as desired. INT-010 Requirements R1 through R3 are administrative to "document" the flow after the fact. This is good practice. These Requirements would be more appropriate in another Standard, possibly INT-011-1 Interchange Coordination Support. R4 is simply trying to enforce that entities don't use the "expedited" approval process for non-reliability reasons. A description in NAESB business practices would be adequate. R5 has reliability value in that an expedited process to have a curtailment approved is desirable. However, a RC can direct people to do something without the Tag. It is definitely needed in the software design to ensure the typical process of a curtailment is efficient. R6 is unnecessary because it is a qualifier for the operation of a dynamic schedule. If someone gets a Tag curtailment, that is their notice to adjust the source generation. They should not have to wait to get that direction (again) from somewhere else.
Individual
Raj Hundal
Powerex
1. Paragraph 81 Considerations: The Coordinate Interchange SDT (CISDT) has reviewed all of the previously posted INT standards, along with stakeholder feedback on the INT standards from Phase 1 of the Paragraph 81 project, as well as outstanding FERC directives assigned to the Coordinate Interchange project. The CISDT believes that all of the requirements remaining in the four standards that are being posted are necessary and require accountability. Please review the mapping document and the list of Paragraph 81 recommendations provided to the INT team as a result of comments received from stakeholders during Phase 1 of Paragraph 81, along with the proposed revisions to the INT standards. If you believe that a specific requirement in the proposed INT-004-3, INT-006-4, INT-009-2, INT-010-2, or INT-011-1 could be better addressed through alternate means than a NERC Reliability Standard, please provide the specific standard and requirement number, along with a specific suggestion for an alternate means to ensure the intended action is accomplished. Some examples of alternate means could include working with NAESB to incorporate the requirement into NAESB business practice standards; moving the requirement into the Guideline and Technical Basis section of

the same standard; or working with a technical committee to develop a NERC guideline. Please be as specific as possible. Comments on INT Standards Powerex would like to thank the CISDT for their hard work in developing a more consolidated and concise version of the Interchange Standards, and respectfully submits the following comments for consideration. General Comments: Powerex has reviewed the latest draft of the Interchange Standards and considers these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are important and prevent entities that transact from providing inaccurate information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is implemented in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations. Powerex believes that it is fundamentally important that all interchange be scheduled using e-Tags, and appropriately evaluated by the reliability entities listed on the e-Tag. Ensuring that all interchange transaction are e-Tagged allows reliability tools, such as NERC IDC and WECC webSAS, to effectively manage congestion through curtailment based on transmission priority. Powerex does not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards. Definitions: 1) The phrases “reliability events” or “reliability assessment” are not defined and are key concepts in these new standards. In INT-010-2 the language was changed to allow exemptions where reliability entities can modify or initiate schedules under abnormal Operating conditions. Now it allows those changes or new schedules to “address reliability events”. Powerex believes that these terms should be defined to remove any ambiguity within these standards. 2) The definition of Intermediate BA has been modified, but it is not clear as to why a new definition is required or why the old definition is inadequate? Further rationale on the changes in definitions would be useful for the industry in evaluating these standards. 3) INT – 009 creates two new definitions for Attaining BA and Native BA. Is there a need to create these new definitions or could we use the currently defined NERC terms such as Sink or Receiving BA, and Source or Sending BA? Further rationale is required as to the reasons for the new definitions, and reasons for not using the current NERC definitions. 4) INT - 009 modifies the definition of Confirmed Interchange. However, the definition only requires Sink BA to verify Arranged Interchange, but it should also state that the Sink BA has also verified that interchange has been approved by all BAs and TSP listed on the e-Tag. INT – 004 – Dynamic Transfer 1) R1 as currently written is only applicable to LSEs that use Dynamic Transfer to serve load, and is not applicable to any PSE that submits a Dynamic Transfer. Powerex believes that the standard should be applied to all entities that use Dynamic Transfers, whether it is used to serve load or provide imbalance service. The Dynamic Transfer, regardless of its intended use, has the same level of impact to the BES, and applying this requirement only to subset of all Dynamic Transfers would not meet the intent and purpose of this standard. 2) R1, the second bullet, we would suggest removing the word “expected”. It is counter-intuitive to suggest that we use the “expected maximum” in the situation where there is “no forecast”. Powerex prefers that the requirements be clear and the removal of “expected” would provide that clarity. 3) The standard is silent on the transmission requirements that would be used for the Dynamic Transfer. It is important that the transmission capacity required to support the transfer of dynamic flow be appropriately obtained, validated and verified prior to implementation. For example, dynamic schedules that are e-Tagged at an average MW level, but do not have sufficient transmission capacity above the average MW level may cause SOL exceedances when dynamic dispatches exceed the average MW indicated on the e-Tag. These types of scheduling issues result in cascading curtailments, which has impacts to other Generators and Loads that must accommodate as a result of the inaccurate scheduling of Dynamic Transfers. It is important that this standard clearly articulate that each dynamic transfer shall procure sufficient transmission to accommodate the maximum dynamic transfer. INT – 006 – Evaluation of Interchange 1) There does not appear to be any requirement that prescribes at a minimum that an Interchange Transaction or Interchange Schedule must be submitted for energy that flows between Balancing Authorities. This should be the case and a new requirement should be developed to reflect this. Otherwise some entities may choose not to submit certain interchange transactions even though it may affect adjacent Balancing Authorities and TSPs. 2) This standard must prescribe at a minimum the verification and validations that must be performed during the reliability assessment by a BA and TSP. Those minimum requirements should not be prescribed in the Technical Guidance section of the standard because they would not be considered mandatory and could be ignored by Responsible Entities. It is imperative that this standard provide clear requirements that ensure BA and TSP are validating impacts, and not allowing transactions to flow that will cause issues within the interconnection. For example, a Source BA should validate and not allow a generator to schedule above and beyond its nameplate capacity to ensure accurate scheduling. Powerex believes that a Source BA will only perform these types of checks if there is a prescribed minimum requirement within a standard, and suggests that the CISDT provide the minimum set of validations. 3) A BA or TSP should deny an interchange that does not accurately provide information especially in relation to the possible BA generation and load. Eg. A generator scheduling 200 MW from a 100 MW nameplate should be actively monitored, verified and denied by BA and VRF/VSF should be established to ensure that BA administers that check. In addition to that BAs should also evaluate and determine if the interchange supports an actual load, and the exports from a Source BA do not exceed generation located in the BA. 4) R2 and R3 does not hold the BA or TSP accountable to correctly approve or deny the interchange request the first time, and allows the entities to rectify the issue through curtailment of the interchange. Powerex believes that these requirements should be modified to rectify a possible loophole that could lead to inefficient scheduling practices. 5) M2 and M3 should measure the times the BA or TSP approves a request without proper verification or validation and then subsequently curtails the interchange once they realize the mistake. The BA or TSP should perform a thorough validation of an Arranged Interchange to avoid such instances which rectify BA or TSP mistakes. Powerex suggests that when a BA or TSP reevaluates a Confirmed Interchange that they note in the comments the reason for the reevaluation. 6) For Attachment 1, there should be a reference point for the time that constitutes whether or not an Arranged Interchange is “on-time” or not. The previous Standard (INT-006-3) used to have the second column of the Timing Requirements table labeled as “IA Assigned Time Classification”. The new table heading for the

second column is not assigned to an entity and states just “Time Classification”. This will result in potential disputes as to who determines and classifies whether or not the RFI is “on-time”. An Entity should be assigned the responsibility to determine the correct time classification (On-Time, Late, etc). Powerex suggests that the Sink BA be the Responsible Entity, and that once the Sink BA assigns a classification that other approval entities should respect that classification. INT – 010 – Modification of Interchange 1) In R1, the term “energy sharing” is not capitalized and thus is open to interpretation, and this leaves the door open for entities to submit RFIs after the scheduling deadlines. In the original INT-010-1, this issue was dealt with by describing the circumstance which this was allowed, specifically “…a loss of resources covered by an energy sharing agreement….”. Either “energy sharing” needs to be defined, or the conditions to allow these modifications should be limited. Powerex suggests reverting back to the current INT-010-1 language use, “…a loss of resources covered by an energy sharing agreement….”. 2) R4.5 states that “Any real-time reliability concern” could lead to a Reliability Adjustment. Powerex believes that this requirement requires further clarification. Could the CISDT provide examples of other reliability concerns outside of R4.1 to R4.4 that would qualify for R4.5? Powerex is not aware of any other reliability concerns than the ones listed for R4.1 to R4.4, and suggests that R4.5 be modified to be more specific by providing details regarding the bounds or that R4.5 be removed entirely. 3) R6 should also apply to Pseudo Ties and not just Dynamic Schedules. Powerex suggests that the language be revised to include Pseudo Ties or that a separate requirement be drafted to limit Pseudo Tie transfers when reliability limits are placed on the interchange.
Individual
Nazra Gladu
Manitoba Hydro
(5) INT-006-4, Application Guidelines - for consistency with other sections of the document, remove all the ‘periods’ from the end of the bullets listed in this guideline. (6) INT-009-2 - for consistency with the other INT standards, remove the ‘periods’ from the end of the bullets listed in this section. (7) INT-010-2 - for consistency with the other INT standards, remove all ‘periods’ from the end of all bullets listed in this standard. (8) INT-010-2, R1 - remove the comma at the end of R1. (10) INT-011-1 - add a period following the definition of Interchange Coordination. (11) INT-011-1, R1.1 - periods are inconsistently being utilized throughout this standard. Manitoba Hydro suggests adding or removing the period(s) from the end of all sentences. (12) General Comment - replace “Board of Trustees” with “Board of Trustees’” throughout the applicable documents/standards for consistency with other standards. (13) INT-006-4, R4 - for reliability reasons the Reliability Coordinator would identify the curtailment and the best resolution from the big picture. If a BA denies the transaction the burden is shifted to the neighbors. Is there a better mechanism or language to resolve this problem? How do you police it? (14) Manitoba Hydro is in agreement with the language in INT-006-4, R5 & R6, but believes that clarity is needed in the Attachment 1 – Timing Table. How does a transaction start 1 hour after the start time?
Individual

Shari Heino
Brazos Electric Power Coop
ACES
Please make it clear that these standards will not apply in ERCOT.
Individual
Ed Skiba
MISO
Tagging of Pseudo-Ties (INT-004 and INT-009) We do not agree that Pseudo-Ties need to be tagged for the following reasons: 1. The asset generator defines the reliability impact, and the allocation (tagging discussion) only deals with allocation of energy, which is a business practice. 2. When a unit is pseudo-tied, a new tie line is created between two entities. These new tie lines are subject to compliance with BAL-001, Requirement R1 and BAL-005-0.2, Requirements R12 – R13. These requirements already implement hourly checks of tie line data. This data provides inputs to the Net Actual Interchange, which are then utilized in the calculation of ACE, which is addressed in the Reliability Standards and requirements indicated above. This creates a potential redundancy of these obligations that could be eliminated. MISO respectfully suggests that the references to Pseudo-Ties should be removed from INT-004-3, Requirements R1-R4 and INT-009-2, Requirement R1. Requirement R2 of INT-009-2 should be removed in its entirety. If the Coordinate Interchange Standard Drafting Team moves forward with tagging Pseudo-Ties, we recommend that language be included that would allow an alternate method for reporting Pseudo-Ties, if they are included in a congestion management procedure such as market flows. Additionally, INT-004 R3.1 needs further clarification so only the BA with the in-kind scheduled loss is required to verify the loss. INT-006 To operate reliably, an entity needs only a net interchange with its neighbor. The details of what customer transactions make up that net interchange is commercial/financial. These requirements represent the functions and actions necessary to effectively manage the details of interchange data. If this information were located in a NAESB Business Practice Standards and the NAESB Electronic Tagging Functional Specification, which are the source of the software specifications, and is open to the industry for comment and voting, that would be adequate. MISO respectfully submits that all of INT-006 could be removed; however, at a minimum, R1 and R6 are the best candidates for removal. If the Coordinate Interchange Standard Drafting Team moves forward with INT-006, the MISO suggests the “shall deny” language in R2.1 be changed to “shall evaluate.” “Denying” is a right of the BA rather than an obligation when it comes to BA’s own capability. For example, if BA default ramp limit is 500 MW import, but in real time BA determines that it can handle one more schedule, it should have the right to approve that schedule. INT-009 The purpose of INT-009-2 is to ensure that entities are operating to a common, but opposite Net Scheduled Interchange (“NSI”). The inputs to the NSI and Net Actual Interchange are then utilized in the calculation of ACE, which is addressed in BAL-005, Requirements R9-R12. Accordingly, the requirements set forth in INT-009-2 are essentially the inputs to the requirements contained in BAL-005, Requirements R9 – R12. The potential redundancy of these obligations could be eliminated if BAL-005 was modified for enhanced clarity including

ensuring that inputs that are currently described in INT-009-2 are addressed in BAL-005-0.2. Such consolidation would provide benefits to reliability generally by ensuring that all obligations relative to the inputs into ACE are clearly described in one location and would eliminate the need for this Standard, which aligns with current efforts to ensure that there is not redundancy in the Reliability Standards. MISO respectfully suggests that the drafting team consider this redundancy as they finalize these standards. INT-010 In implementation, Requirements R1 through R3 are essentially “administrative” as they ‘document’ the flow and associated actions after-the-fact. Because the operating time in which the actions and flow were necessary has already elapsed, it is important to note that Requirements R1 through R3 are not necessary for the reliability of the Bulk Electric System. Therefore, while it is good practice to document such activities, such documentation obligations are not appropriate for inclusion in the Reliability Standards. More specifically, the Reliability Standards should contain only requirements for activities that are necessary to maintain the reliability of the Bulk Electric System. After-the fact documentation activities do not meet this essential criterion for inclusion as requirements in the Reliability Standards. MISO respectfully suggests that such requirements be documented in best practices outside of the Reliability Standards. Further, MISO respectfully requests that, if Requirement R1 is retained, the language is revised to ensure that the requirement more clearly states that its intended application is to After-The-Fact reliability adjustments. R4 is trying to ensure that the ‘expedited’ approval process reserved for reliability reasons is not utilized for non-reliability reasons. This documentation will only be reviewed “after-the-fact” and will not ensure that obligations and process are properly fulfilled and utilized in the normal course of business. Because the operating time in which the relief was requested has already elapsed, it is clear that Requirement R4 is not necessary to ensure the reliability of the Bulk Electric System. Therefore, while it is good practice to document the condition that prompted a request for relief, such documentation obligations are not appropriate for inclusion in the Reliability Standards because the Reliability Standards should contain only requirements for activities that are necessary to maintain the reliability of the Bulk Electric System. After-the fact documentation activities do not meet this essential criterion for inclusion as requirements in the Reliability Standards. MISO respectfully suggests that such requirements be documented in best practices outside of the Reliability Standards. MISO further notes that such documentation activities may distract entities by requiring the relation of real-time BES events to congestion management actions when such entities and their personnel should remain focused on relieving the system conditions. Finally, the requirement does not appear to leverage existing processes. For example, when a curtailment is requested through the IDC, many entities indicate the constrained element in the curtailment request. An alternative approach would be to require a reference to the initiating system condition at the time the relief is requested. More specifically, a reliability adjustment should not proceed through the curtailment process without the identification of the constrained element or condition in the adjustment request. MISO supports the expedited curtailment approval process set forth in Requirement R5. MISO respectfully suggests that Requirement R6 is unnecessary because it is a qualifier for the operation of a dynamic schedule that is already covered by an existing process, i.e., when someone gets a Tag curtailment, they have received notice to adjust the source generation. INT-011 MISO requests clarification

regarding how the INT-011 standard will be coordinated with changes to the IRO-006 Standards. Currently, IRO-006-EAST-1 R.3 has no provision for the Reliability Coordinator issuing a TLR to instruct the receiving Reliability Coordinator to curtail intra-Balancing Authority Area Point to Point Transmission Service, and IRO-006-EAST-1 R.4 has no provision for the receiving Reliability Coordinator to instruct the Balancing Authority to implement intra-Balancing Authority Point to Point Transmission Service schedule change requests.
Individual
Michael Falvo
Independent Electricity System Operator
We do not believe that any specific requirements in the proposed INT-004-3, INT-006-4, INT-009-2, INT-010-2, or INT-011-1 could be better addressed through alternate means than a NERC Reliability Standard. We generally agree with the recommendations that a number of the INT standard requirements can be addressed through the functional specifications of E-tag, especially those that address information exchange at the Arranged Interchange stage. Still, the requirements for the e-tag submission process need to be retained somewhere. If this process is to be moved over to NAESB's business practices, then it is important that coordination with NAESB be initiated as soon as possible to ensure its business practices are ready for implementation when the revised INT standards become effective.
Individual
Chris Nebrigich
Idaho Power Co.
INT-004-3: In R1 I have some concerns with the requirement to submit dynamic/pseudo schedules at the expected maximum MW profile if no forecast is available. Seems like this could create some confusion on what is considered a forecast. The transmisison is typically set at maximum and energy set at expected. Not sure if we need an option specifying what to tag if there is no forecast. I don't believe that R3 or R4 provide any reliability benefits to the Bulk Electric System. These Requirements could be addressed in another document. Also, I noticed that several comments have stated that the industry should consider retiring all INT Standards and moving some if the requirements that impact reliability to the BAL Standards. I feel that there is value in retaining the INT Standards and not integrating them into the BAL Standards.
Individual
Michael Lowman
Duke Energy
Duke Energy submits the following comments: INT-004 The elimination of PSE in the Applicability Section of this standard and the associated requirements moves away from the NERC Functional Model. Duke Energy suggests a slight modification to R1, " Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted by the PSE as an on-time Arranged Interchange to

the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie at either:" Duke Energy believes that R3.2 should only include the RC. If a different Registered Entity is required, this issue should be addressed by a Regional Reliability Standard. INT-006 Duke Energy suggests replacing "Balancing Authority Area" with "Balancing Authority" for the definition of Adjacent Balancing Authority. Duke Energy would like for the SDT to consider adding a provision to R6 when scheduling systems are down, a move to a back-up control center, etc. These types of events could create a compliance risk with Attachment 1, Column D. Duke Energy also seeks clarification on the term "reliability assessments". Who is responsible for conducting these "reliability assessments"? Per the functional model, TSPs do not conduct these types of assessments. Is it the intent of the SDT for the TSP to conduct a reliability assessment prior to approval of an Arranged Interchange? INT-009 Duke Energy suggests changing the language in R1.2 to read, "Agree to the direction of the Composite Interchange with Adjacent Balancing Authority."
Individual
John Bee
Exelon and its' Affiliates
Exelon agrees with the rationale for INT-004 R3 and R4, but feels that they but fall short of a requirement for the BA or NAESB to periodically (annually at minimum) communicate the list of Pseudo Tie lines within their zone to each Distribution Provider (DP) / Electric Distribution Company (EDC). Additionally, DPs/EDCs with no pseudo-ties in their zone should likewise be informed as well. Exelon would like to see the requirements address dynamic load that switches from LSE to LSE or from LSE to the Provider of Last Resort (POLR). The requirements should also address the situation of creating dynamic schedules for load at aggregate nodes. Exelon would like to see the order of the requirements in INT-004 changed from: R1, R2, R3, R4 to R3, R4, R1, R2 because we feel that proper registration of a Pseudo Tie Line must occur in order for requirements one and two to be effective. Finally, Exelon feels that there should be an exception to Violation Severity Levels for R1 and R2 in the situation where the Pseudo Tie Line was not properly registered by the BA in R3 and/or R4. INT-009-2 includes new definitions for Dynamic Schedule and Pseudo-Tie requiring that these values be treated as Interchange Schedules and Actual Interchange, respectively, and included in ACE equations. It is confusing, then, that R1 should specify that Composite Confirmed Interchange is to be calculated without inclusion of Dynamic Schedules and Pseudo-Ties. As Dynamic Transfers represent inputs to the ACE equation, and measurements against which a BA is managing its balancing function, to exclude them from the Composite Confirmed Interchange seems to paint an inaccurate picture of the Interchange between two Balancing Authorities. If the intention is to not skew Composite Arranged Interchange by the inclusion of values that change in Real Time with no settled value available until after-the-fact, that can be easily accomplished by stipulating that estimated values of Dynamic Schedules and Pseudo-Ties not be included in Composite Confirmed Interchange, and that the real-time values should be used for calculation of Composite Confirmed Interchange in the Real Time horizon, with the agreed on after the fact values used for calculation of Composite Confirmed Interchange in the after the fact horizon.

Group
SERC OC Review Group
Sammy Roberts
We recommend that the SDT consider utilizing existing functionality through the ownership factor in the IDC to document real time flows and impacts of Pseudo Ties. The concern is the compliance risk and administrative overhead to adjust these tags on an hourly basis. INT-004-3 The SDT is requested to clarify Requirement 3.3.2. Each of the Balancing Authority's associated Reliability Coordinators (in the Eastern Interconnection) or associated Transmission Operators (in the Western Interconnection) has confirmed that sufficient information to reliably manage the Pseudo-Tie has been provided. Modify statement: Pseudo Tie Tags will require adjustments almost every hour to stay in compliance, creating the need for costly software, increased staff to manage, and extremely large tag files which will choke systems and internal processes. The existing functionally in the IDC, (add: when used, and current reporting of market flows,)(delete: if made a requirement) will provide greater visibility, accountability, and more accurate data-all contributing to increased reliability. The approval and coordination of Pseudo Ties prior to implementation is addressed in R 3 & 4 and should be adequate to provide the necessary visibility and awareness between all impacted BAs, TSPs, and RCs. INT-006-4 We recommend that R4 be reworded based on current NERC Glossary. The Glossary currently defines "Reliability Adjustment", "Arranged Interchange", and "Curtailment". We would suggest that the new language read: R4. Each Balancing Authority receiving a Reliability Adjustment (insert: to) Arranged Interchange shall approve or deny it prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 4.1. If a Balancing Authority denies a Reliability Adjustment (insert: to) Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial. Further, we recommend deleting the "Reliability Adjustment Arranged Interchange from the proposed standard. INT-009-2 These following two terms (Attaining Balancing Authority and Native Balancing Authority) are different than other standards and customary terminology used in the industry. To avoid potential confusion or error it is recommended that "Source BA and Sink BA" be utilized. Attaining Balancing Authority: A Balancing Authority bringing generation or load into its effective control boundaries through a dynamic transfer from the Native Balancing Authority. Native Balancing Authority: A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a dynamic transfer. INT-010-2 We recommend that the term Reliability Adjustment Arranged Interchange be reworded based on current NERC Glossary. The Glossary currently defines "Reliability Adjustment", "Arranged Interchange", and "Curtailment". We would suggest that the new language read: R4. Each Reliability Coordinator, Balancing Authority or Transmission Service Provider that initiates a Reliability Adjustment (insert: to) Arranged Interchange must have experienced one or more of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same Day Operations, Real Time Operations] M4. Each applicable entity shall have evidence such as dated and time-

stamped logs, voice recordings, electronic records, or other similar evidence that when it created a Reliability Adjustment (insert: to) Arranged Interchange R5. Each Sink Balancing Authority shall distribute any Reliability Adjustment (insert: to) Arranged Interchange only to the Source Balancing Authority for reliability assessment. [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] M5. The Sink Balancing Authority shall have evidence such as dated and time stamped electronic logs or other similar evidence that it distributed any Reliability Adjustment (insert: to) Arranged Interchange only to the Source Balancing Authority for reliability assessment. (R5) R6. Each Balancing Authority involved in a Reliability Adjustment (insert:to)Arranged Interchange involving a Dynamic Schedule shall use agreed upon values that ensure any limit established by the Reliability Adjustment Arranged Interchange is not exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] M6. The Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that following any Reliability Adjustment (insert: to) Arranged Interchange involving a Dynamic Schedule it used agreed upon values that ensured any limit established by the Reliability Adjustment Arranged Interchange was not exceeded. (R6) Further, we recommend deleting the "Reliability Adjustment Arranged Interchange from the proposed standard. The SDT is request to clarify the term "energy sharing" used in R1: Each Sink Balancing Authority shall ensure that a Request for Interchange is created within 60 minutes of the start of the energy sharing, and with a start time no more than 60 minutes beyond the start of the energy sharing for Interchange scheduled in duration of more than 60 minutes as part of an energy sharing agreement NAESB Business Practice Standards – There is a concern among the group on how the NERC Reliability Standards will remain in lock-step with the NAESB Business Practice Standards. Has there been an agreement reached on a process to use? The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Kathleen Goodman
ISO New England Inc.
we agree with NPCC RSC members comments and offer additional input as well.
We agree with the Independent Expert Panel's recommendation that a number of the Reliability Standards are being addressed through the functional specifications. INT-004 ISO-NE does not currently have interchange associated with dynamic transfers. However, where dynamic transfers are utilized we believe that the transparency these requirements provide is necessary for reliability. INT-006 Based on the ISO-NE market design, ISO-NE needs only a net interchange with our neighbor to operate reliably. The details of what customer transactions make up that net interchange is purely commercial/financial under our market design. ISO-NE also does not have loop flow issues with our neighbors and the individual transaction information is not required to manage congestion on our system. If these INT-006 requirements were not contained in NERC standards and interchange transactions are not acted upon in the timeframes defined in these requirements, the ISO-NE markets would continue to economically dispatch generation with respect to any interchange that is available.

If no interchange were available the ISO-NE markets have mechanisms in place to ensure that load is served. As such, ISO-NE agrees with the Expert Panel’s observation that guidelines exist in the functional specification for electronic tagging. However, the details in that specification were developed based on the language in these standards. If these requirements are removed from the NERC standards, they must reside somewhere in business language that can be voted on by the industry that would continue to drive changes to the eTag specification. If this information were located in a NAESB Business Practice Standards, which are the source of the software specifications, and are open to the industry for comment and voting, that approach would be adequate to serve the reliability needs of ISO-NE. INT-009 ISO-NE believes that BAL-005 R9-R12 could be modified to be clearer and incorporate the language/intent of R1 and R2 of INT-009. INT-009 R3has been present in some form since the original policy language was converted to standards. While it is an obvious function that is required in order for the flow to be set as desired, this is comparable to generators needing to be told where to operate but there is no NERC requirement for ‘WHO’ to notify them. We believe this requirement can be removed. INT-010 R1-R3 are administrative tasks to document the flow directed by an RC after-the-fact. Since they are after-the-fact actions, they are clearly not necessary for reliability. While we agree is necessary for transparency we believe it would be adequate to locate this requirement in a NAESB Business Practice Standard. R4 is trying to enforce that entities do not use the ‘expedited’ approval process for non-reliability reasons. ISO-NE believes a description in NAESB business practices would be adequate. R5 can impact reliability; an expedited process is needed to ensure curtailments occur in a timely manner.. However, since an RC can direct an entity to take action without an approved eTag, it may be adequate to have the NAESB Business Practice Standards define who those approval entities must be to support the software design that would occur for typical interchange processing. The description in the Background section for R6 does not quite align with the requirement language. We believe that R6 could be unnecessary if the language in BAL-005 R9-R12 are updated to use results based standard language. This proposed requirement seems to more of an instruction of HOW someone with a Dynamic Schedule should follow a reliability adjust; and may be more appropriate in the Guidelines and Technical Basis section of INT-004. Another observation/question, is the language in INT-004 R2.3 intended to have the same outcome? There are other NERC Standards that require operating entities to follow directions of their RC, TOP and BA, so this is already covered elsewhere.
Individual
Michelle R. D'Antuono
Occidental Power Services Inc.
INT-011-1, Applicability Section and R1. The market structure and market operations of ERCOT renders R1 inapplicable. There is only one Balancing Authority within ERCOT (ERCOT itself) and, therefore, no intra-Balancing Authority Interchange. There is interchange across the DC ties between ERCOT and the Western and Eastern Interconnections, but this standard only applies to "intra-Balancing Authority areas." The Applicability Section should be revised to say "4.1.1. Load Serving Entities, except those in ERCOT."

Individual
Andrew Gallo
City of Austin dba Austin Energy
Austin Energy (AE) requests that the SDT review the applicability of these standards in the ERCOT Region. Because ERCOT ISO is the only Balancing Authority in the ERCOT Interconnection, Dynamic Interchange from or to another Balancing Authority does not occur in the ERCOT Interconnection. AE requests the SDT make the applicability clear in the Applicability section using an approach similar to the MOD A project. Example text would be: 4.3 Exemptions: The following is exempt from INT-004-3. 4.3.1 Functional Entities operating in the ERCOT Region. AE believes this exemption is appropriate for all the INT standards in this posting, including the newly proposed INT-011-1.
Group
PacifiCorp
Kelly Cumiskey
PacifiCorp agrees that the proposed revisions should be addressed within the INT standards; however, there are several areas where the revisions are too broadly constructed and introduce a level of ambiguity that would make compliance with the INT standards challenging. PacifiCorp's concerns are highlighted below: • INT-004-3 R1 and R2: PacifiCorp does not believe there is a reliability benefit to the BES of requiring a Request for Interchange to be submitted as an on-time Arranged Interchange to the Sink Balancing Authority for a Pseudo-Tie. Pseudo-Tie tags do not calculate into any portion of the ACE and are used purely for accounting purposes. • INT-004-3 R3.2: PacifiCorp contends that for a BA's associated RC or TOP to confirm that "sufficient information" to reliably manage the Pseudo-Tie has been provided, it must first be clear what constitutes a "sufficient" amount of information. This language is too broad and subject to interpretation and is therefore difficult to measure. • INT-006-4 R2.2: PacifiCorp suggests the SDT change Balancing Authority to Intermediate Balancing Authority in order to clarify who is to complete the denial or curtailment. The Source and Sink Balancing Authorities are already required to perform this action under R2.1. • INT-006-4 R3.1: PacifiCorp suggests that that SDT expand the description of the "transmission path" to describe other criteria beyond "proper connectivity of adjacent TSPs" such as sufficient OASIS rights, energy profile, physical path, and transmission profile. • INT-006-4 R4: PacifiCorp is uncertain of the reliability benefit of the Balancing Authority communicating a denial to the Reliability Coordinator after the fact and seeks justification from the drafting team. A denial reason is required on the e-Tag which should serve as proper notification. • INT-009-2: o R1: PacifiCorp seeks further clarification of the defined term, "Composite Confirmed Interchange." Specifically with respect to how Composite Confirmed Interchange differs from Net Scheduled Interchange. o R2: PacifiCorp believes that this requirement is redundant to BAL-005-0.2b R12.1. • INT-010-2 R6: PacifiCorp believes the term "agreed upon values" should be amended to provide more clarity. PacifiCorp requests the SDT specify the method expected to be implemented in order to determine "agreed upon values" used by each BA to ensure limits are

not exceeded. Specifically, PacifiCorp wonders if the agreed upon value is the value provided by the Reliability Adjustment Arranged Interchange or if the agreed upon value is based on a verbal communication. PacifiCorp supports the development of new draft Standard INT-011-1. This will support reliability of the BES because creation of the path using Point to Point Transmission Service indicates congestion is possible on that path and management of the path is needed to avoid leaning on other parallel paths.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC OC Review Group
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
INT-004-3 The PPL NERC Registered Affiliates recommend removing language concerning Pseudo Ties from this Standard. It appears the R1 and R2 are attempting to require real-time hourly tags for Pseudo Tied loads. These Requirements would necessitate adjustments almost every hour to stay in compliance, creating the need for costly software, increased staff to manage, and extremely large tag files which will choke systems and existing reliable processes. The existing functionally in the IDC provides greater visibility, accountability, and more accurate data - all contributing to increased reliability. Also, Balancing Authorities are already aware of the effects of Pseudo Ties upon their systems because such effects are accounted for in their ACE equations. It is unclear what the technical justification is for requiring Pseudo Tied loads served by DNRs via NITS to use the Arranged Interchange process outlined in this Standard. Furthermore, we agree and support the SERC OC and MISO comments relating to tagging of Pseudo Ties in INT-004-3.
Group
NERC Compliance Policy
Randi Heise
In reviewing the INT standards associated with this Project, it would be helpful to have all impacting changes to the document redlined for review. Dominion suggests the SDT adopt the best practices of denoting the status of all changes rather requiring the reader to deduce the status from a range of statuses requiring additional research. For example, INT-011.1 includes a newly defined term identified as “This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here.” Underlining added for emphasis. Dominion would like to state that in addition to INT-004-3, the revised definitions, “Dynamic Schedule” and “Pseudo-Tie” are also associated with reliability standards BAL-2-WECC-2 - Contingency Reserve, BAL-003-0.1b - Emergency Response and Bias and BAL-005-0.2b - Automatic Generation Control, as noted in

the Definitions of Terms Used in Standard section. Dominion believes that future instances of any change to a standard should be provided to the balloting body as red-line documents and noted for ease of modification identification and review. Dominion questions whether the word 'desires' in Requirement 1 should be replaced with 'is required'? We doubt that a PSE would desire to submit Requests for Interchange if it isn't required to do so. Dominion commends the SDT for concise mapping of the current requirements in the standards to the revised or relocated requirements.
Individual
Bob Thomas, and Alice Schum
Illinois Municipal Electric Agency
Agree
SERC OC Review Group, and MISO
Individual
Richard Vine
California Independent System Operator
INT-006 At a minimum, R1 and R6 are the best candidates for removal, though all of INT-006 could be removed. To operate reliably, an entity needs only a net interchange with its neighbor. The details of what customer transactions make up that net interchange is commercial/financial. These requirements represent the functions and actions necessary to effectively manage the details of interchange data. If this information were located in a NAESB Business Practice Standards and the NAESB Electronic Tagging Functional Specification, which are the source of the software specifications, and is open to the industry for comment and voting, that would be adequate. INT-009 BAL-005 R9-R12 could be modified to be clearer and incorporate the language/intent of these requirements. Thus, this Standard would no longer be necessary. When specifically reviewing R3, although this requirement has been present since the original policy language was converted to standards; it is an obvious function that is required in order for the flow to be set as desired. This is comparable to generators needing to be told where to operate but there is no requirement for 'who' to notify them. INT-010 R1-R3 are administrative to 'document' the flow after-the-fact. Real Time has already passed so it is not necessary for reliability. It is good practice to do these activities but they should be documented in best practices outside of the requirements. R4 is simply trying to enforce that entities don't use the 'expedited' approval process for non-reliability reasons. A description in NAESB business practices would be adequate. R5 may have some reliability value in that we desire an expedited process to have a curtailment approved. R6 is unnecessary because it is a qualifier for the operation of a dynamic schedule. If someone gets a Tag curtailment - that is their notice to adjust the source generation. INT-011 INT-011 R.1 is needed to address the FERC directive identified in Order 693 (see Paragraph 817). Additionally, this directive was not one of the directives FERC suggested to withdraw in Notice of Proposed Rulemaking RM13-8-000 issued June 20, 2013.
Individual

Oliver Burke
Entergy Services, Inc.
Please consider utilizing existing functionality through the ownership factors in the IDC to document real time flows and impacts to Pseudo Ties. The concern is the compliance risk and administrative overhead to adjust these tags on an hourly basis. INT-004-3 The Title of this standard has been modified from “Dynamic Interchange Transaction Modifications´ to “Dynamic Transfers”. Entergy recommends that it should be “Dynamic and Pseudo-Tie Interchange Transactions” to reflect inclusion of Dynamic Schedules and Pseudo-Ties. Effective Date: Since certain requirements, as written in this standard, are dependent on NAESB action to modify Electric Industry Registry, the effective date should reflect this dependency. R1 – “on time” included in this requirement is not defined in this standard. Timing requirements that were included in INT-005-3 are now included in INT-006-4. Entergy suggest that either “on-time” referred to in this requirement specifically point to INT-006-4 Attachment 1 or this term be removed from this requirement. Similar reference in M-1 should be adjusted accordingly. There is no need to include the expected maximum MW profile. If the entity can come up with the maximum MW profile, it can also come up with the expected average MW profile. There is no benefit or reliability impact of knowing maximum MW profile. Entergy recommends not including the second bullet for maximum MW profile in the standard. R2 – The language in this requirement is odd. …ensure the Confirmed Interchange…is reviewed and updated if needed for the next available….. This language is loose and it does not appear like a Standard requirement language. This is modification of the existing requirement that used a threshold of 10% or 25 MW for updating the profile. However, the new language by including the term “if needed” makes it vague. This requires comparing the actual integrated energy for an hour to be compared with the average energy profile for the next hour. The average energy profile for the next hour may actually be required to be more than 10% or more than 25 MW different from the previous hour. There is also not enough time for adjustment of the energy profile for the next hour as the actual integrated energy for an hour cannot be determined till after completion of that hour. Even though this requirement was already in INT-004-2, Entergy recommends to remove this requirement as it does not serve any reliability purpose, is just administrative burden, and difficult to implement. R-3 and R4 – These requirements are administrative and commercial in nature as these require to verify how losses will be accounted for and that sufficient (vague) information to reliably manage the Pseudo-Tie has been provided. These require verifying if these Pseudo-Ties are registered in the NAESB Electric Industry Registry, which capability does not even exist currently. These requirements do not have any reliability impact. Entergy recommends that these requirements should not be included in the reliability standards. Pseudo-Tie Tags will require adjustments almost every hour to stay in compliance, creating the need for costly software, increased staff to manage, and extremely large tag files which will choke systems and internal processes. The existing functionally in the IDC (if made a requirement) will provide greater visibility, accountability, and more accurate data – all contributing to increased reliability. The approval and coordination of Pseudo Ties prior to implementation is addressed in R3 & R4 and should be adequate to provide the necessary visibility and awareness between all impacted Bas, TSP, and

RCs. Please clarify Requirement 3.3.2. Each of the Balancing Authority's associated Reliability Coordinators (in the Eastern Interconnect) or associated Transmission Operators (in the Western Interconnection) has confirmed that sufficient information to reliably manage the Pseudo-Tie has been provided. INT-006-4 The term "Reliability Adjustment Arranged Interchange" is not consistent with other NERC standards and the recommendation is to use "curtailment request". R1 – Reference to " so that these entities can conduct a reliability assessment of the Arranged Interchange before Arranged Interchange is implemented" is unnecessary in this requirement. Requirements for assessments are detailed in other requirements. Entergy recommends removing this reference/phrase. Attachment I, Column A specifies initial distribution of all Arranged Interchanges in less than or equal to one minute of its receipt. Description given in this requirement is very confusing. The phrase in second/last sentence "exceeding the times specified in Attachment 1, Column A..." tends to imply that the distribution can occur in more than one minute. The intent of this requirement needs to be clarified and language modified accordingly. R-2 – Foot note 2 is redundant. Since there is no requirement to provide response to any other requests, the foot note does not add any value. R3 – Foot note 3 is redundant. Since there is no requirement to provide response to any other requests, the foot note does not add any value. Though the note in Rationale for this requirement indicates that TSP may deny for other reasons, R3.1 limits the denial only if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid. Since Rationale is not part of the standard Entergy recommends including "other reasons" included in the requirement. TSP can deny if there are not enough scheduling rights (MW available on TSR). R6 – The language of the requirement is odd. Entergy suggests the language to be changed to: Each Sink Balancing Authority shall distribute all notifications of whether an Arranged Interchange was transitioned to Confirmed Interchange to the following entities such that on-time Confirmed Interchange can be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: Interchange Authority – Since Interchange Authority is being replaced by the Sink Balancing Authority in these standards, definition of Interchange Authority is not needed any more. SDT should recommend deletion of the definition of Interchange Authority from NERC Glossary. Attachment 1, Column C is not referenced in any Standard. It does not seem to have meaning? It was earlier referenced in INT-008-3 R1 that has been moved to INT-006-3 R6 and reworded. Entergy recommends reviewing this and modifying the language of R6, if needed. INT-009-2 These following two terms (Attaining Balancing Authority and Native Balancing Authority) are different than other standards and customary terminology used in the industry. To avoid potential confusion or error it is recommended that "Source BA and Sink BA" be utilized. Attaining Balancing Authority: A Balancing Authority bringing generation or load into its effective control boundaries through a dynamic transfer from the Native Balancing Authority. Native Balancing Authority: A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a dynamic transfer. INT-010 R1 – What is the reason of using the term "created" in place of originally used term "submitted" in existing standard? The Request for Interchange needs to be submitted and not only created, therefore Entergy recommends keeping the term "submitted". R2 – Same remark as R1 for the

term “created”. R3 – Same remark as R1 for the term “created”. R5 – Use of the term “only to the Source Balancing Authority for reliability assessment tends to imply that if got distributed to any other entity, it is a violation. Entergy recommends removing the term “only” in this requirement. The term “Reliability Adjustment Arranged Interchange” is not consistent with other NERC standards and the recommendation is to use “curtailment request”. The SDT is requested to clarify the term “energy sharing” used in R1: Each Sink Balancing Authority shall ensure that a Request for Interchange is created within 60 minutes of the start of the energy sharing, and with a start time no more than 60 minutes beyond the start of the energy sharing for Interchange scheduled in duration of more than 60 minutes as part of an energy sharing agreement The term “Reliability Adjustment Arranged Interchange” is used throughout the standard. We recommend changing and use “curtailment request”. NAESB Business Practice Standards – There is a concern among the group on how the NERC Reliability Standards will remain in lock-step with the NAESB Business Practice Standards. Has there been an agreement reached on a process to use? INT-011 This standard has been developed in response to the FERC directive. This will also facilitate Parallel Flow Visualization (PFV) project that NAESB is working on. In case this standard does not get included in the final NERC standards, this will adversely impact the NAESB effort. Entergy supports this standard.
Group
Hydro One Networks Inc.
Sasa Maljukan
Agree
NPCC RSC
Group
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing
Pamela Hunter
We agree with the SDT’s disposition of the Paragraph 81 recommendations in the current draft of the INT standards posted. Southern Company would like to take this opportunity to point out that there will be additional burdens and administrative tasks from a compliance perspective due to changes introduced in the current INT proposed standards, namely the requirement to E-tag Pseudo-Tie transactions. Southern believes that the current implementation of the IDC allows for adequate representation of Pseudo-tie transactions for consideration in reliability curtailments. It appears to us that the requirement to E-tag Pseudo-Tie transactions will result in increased regulatory exposure for entities with little net benefit to the overall reliability of the bulk electric system.
Individual
Silvia P. Mitchell
NextEra Energy

NextEra Energy (including Florida Power & Light Company (FPL)) is registered for all functions, except Reliability Coordinator (RC), and FPL is the RC agent for the Florida Reliability Coordinating Council (FRCC). As such, NextEra has considerable experience with interchange, and, based on this experience it finds that all the Interchange Standards should be retired. There are a number of reasons that NextEra has come to this conclusion. One, all the Interchange Standards meet the P81 criteria, including there is no reliability gap resulting from the retirement of the INT Standards. Second, NAESB already is regulating interchange via the e-tag system. Third, the independent expert's report supports the elimination of the Interchange Standards. Fourth, the few FERC outstanding directives issued on Interchange are outdated, and, therefore, should not impact the retirement of the Interchange Standards. In short, NextEra strongly recommends that the next posting of the INT Standards be focused on retiring all of the INT Standards. Interchange Standards meet the P81 criteria. The P81 criteria requires that both Criteria A and B be met to indicate that a Reliability Standard is appropriate to be retired. Criterion A of P81 states: The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES. Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." Interchange Standards do little to promote reliable operation, because: (i) as the independent expert report indicates all the interchange specifications are set forth in NAESB's e-tagging specifications and as well (ii) there is no correlation between the Interchange Standards and "operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system" do not occur. For those few aspects of Interchange Standards that are designed to ensure interchange is included in real-time monitoring and operations as well as situational awareness, these aspects are already covered in BAL-001, BAL-002, BAL-004, BAL-005, BAL-006, EOP-001, EOP-002, IRO-005, IRO-006, TOP-002, TOP-005. There are also WECC-specific interchange Standards and it is addressed in various MOD and TPL Standards. The INT Standards have become outdated, redundant administrative requirements that do little, if anything, to promote reliability. Thus, the Interchange Standards also meet Criteria B1 (administrative in nature), B3 (purely documentation), B6 (commercial or business practice) and B7 (redundant with other requirements and NAESB). The current paradigm of Standards drafting, as set forth in the P81 criteria, as well and the independent expert's decision-trees, requires that the drafting team closely scrutinize the need for the INT Standards. NextEra views the INT Standards as providing no value and addressing no reliability gap. Accordingly, given the current approach to drafting Reliability Standards, the INT Standards should be retired as soon as possible. NextEra could go through each requirement and apply the above criteria, but for SMEs in this area, the application of the P81 criteria should be fairly straightforward. NextEra will send an SME to the next drafting team meeting to help the team focus on retiring requirements. Also, while the drafting team may believe it must have Standards to comply with certain Commission directives, these directives are outdated

and with some education we believe the Commission will understand that interchange is more than sufficiently regulated via other Reliability Standards and NAESB.
Group
ACES Standards Collaborators
Jason Marshall
(1) In general, most of the requirements in the INT standards either are business practices or steps that occur in tagging software that do little if anything to support reliability and there are only a few basic things that need to occur with Interchange to support reliability. First, tagging dynamic schedules and pseudo ties and intra-BA transactions are commercial equity issues intended to ensure these transactions are curtailed equitably with other transmission service. RC, BAs and TOP can always re-dispatch (which is essentially all a transmission service curtailment is) in other ways. The whole purpose of the IDC and WECC USF is to ensure transmission service is curtailed equitably and in an organized fashion. If commercial equity was not an issue these tools would not exist. Second, many of the requirements dealing with distributing Arranged and Confirmed Interchange are in fact software tool application and not necessary. Third, the adjacent BAs must agree to a common interchange number with equal value but opposite sign. This would include ensuring that dynamic transfers are accounted for correctly in either scheduled interchange or actual interchange and utilizing a common meter point. Technically, the interchange could even be wrong as long as both BAs are controlling to the same number but opposite in sign which avoids frequency deviation. While we would agree it is advantageous to build the interchange values from individual interchange schedules, from a reliability point of view, it is not necessary. However, these steps really boil down to accounting for each transaction, the ownership, energy imbalance, and various sundry of other commercial equity concerns. Thus, each schedule essentially represents a business transaction and is accounted for separately to facility business processing and making it easier to identify errors in interchange. Second, the BAs must ensure that they can support the magnitude of the Interchange including the ramping capability. Third, the transmission system must be able to support the transaction. However, from a practical perspective, the only check that is performed here is to ensure that a valid transmission service reservation is utilized and not overrun. Failing to allow Arranged Interchange that utilizes a perfectly valid transmission service reservation to proceed to Confirmed and Implemented Interchange could be viewed as a tariff violation unless there is an imminent transmission threat (i.e. violated IROL). The Arranged Interchange could be utilizing a higher priority transmission service reservation that will bump other Implemented Interchange that utilizes lower priority transmission service. In essence, the request is submitted to re-allocate transmission service to the highest priority through tools such as the IDC. Thus, most TSPs are reluctant to not allow Arranged Interchange to transition to Confirmed Interchange due to transmission constraints. (2) We disagree with requiring Dynamic Schedules and Pseudo-Ties to be tagged in a reliability standard (INT-004-3). The purpose of tagging these schedules is a commercial equity issue. By NERC definition (both proposed and existing), a Dynamic Schedule is already correctly implemented in both the Attaining and Native Balancing Authorities. Thus, load, generation, and interchange will be

balanced. Thus, the only reliability concern that is left is if the transmission system can handle the Dynamic Schedule. Since the vast majority of these Dynamic Schedules are grandfathered and, those, that are not will utilize firm transmission, the transmission system can certainly handle these Dynamic Schedules. This means that the only issue left is that it is a commercial equity and transparency issue. Because it has been historically recognized that these transactions will be accommodated on the transmission system in all but the rarest cases, years ago, market participants recognized that if these transaction were not tagged and firm transmission was curtailed, these transaction would not receive any curtailment. At that time, market participants held seats on NERC groups such as the Operating Reliability Subcommittee and insisted on these transactions being tagged for fairness. This means it is a business practice and rightfully belongs in a NAESB standard. Even the purpose statement of the standard is clear that the purpose is to ensure that the transactions are accounted for in congestion management procedures appropriately. This is not a reliability concern and it should be transitioned to a NAESB business practice. (3) Congestion management procedures (such as the IDC and WECC USF) cannot be viewed as primarily reliability tools and, thus, tagging transactions is essentially a commercial equity issue to ensure fair and non-discriminatory transmission service. Rather these tools are implemented to help ensure an orderly prioritization of transmission service. They help ensure that only those transactions with a significant impact are curtailed on a flowgate or transfer path and that the lowest priority transmission service is curtailed first. They also help to reallocate flows when higher priority transmission is scheduled on an already congested flowgate or transfer path. FERC has held in Order No. 693 that congestion management tools such as the IDC in essence are not reliability tools by refusing to allow them to be the only tool used to unload a flowgate experiencing an IROL exceedance. IRO-006 reflects this. NERC's CEO recently supported this position at the August 2013 NERC BOT meeting in Montreal when he stated the reason NERC no longer supports the IDC is because it is a congestion management tool and not a reliability tool. We strongly recommend the review team eliminate all non-reliability concepts from the INT standards. (4) INT-004-3 - The reliability impact of Dynamic Schedules will be addressed appropriately in the agreement established between the Attaining and Native BAs. The agreement will include items such as common metering points, implementation dates, testing requirements, etc. No additional reliability standards requirements are necessary for Dynamic Schedules. A NERC reliability guideline might be appropriate to identify what should be in these agreements and how to implement a Dynamic Schedule successfully. (5) Only the definition for Dynamic Schedule is proposed to be modified. Dynamic Interchange Schedule is also defined the same as Dynamic Schedule. If the drafting team is proposing to eliminate Dynamic Interchange Schedule this should be stated clearly or it should also be included in the definition. If it will be retired, all standards should be reviewed to ensure it is not use elsewhere. (6) INT-004-3 R2 – The "is reviewed" should be modified in the standard. The checks that must occur to move Arranged Interchange to Confirmed Interchange could be viewed as a review. Thus, we suggest that the wording should state more directly what is required. The energy profile is to be compared against the actual energy flow. (7) INT-004-3 Part 2.3 – This could be stated more simply. If the RC or TOP instructs the LSE to update the tag, they should. (8) INT-004-3 R3 – This is clearly a business practice as stated in the rationale box and implementation plan. The requirement is expected to be implemented in a NAESB standard. This makes it clear this is a business practice and we cannot support this as reliability standard requirement enforceable by sanctions. (9) INT-004-3 – Part 3.2 implies that a BA can have more than one reliability coordinator. We do not believe this is possible from a practical perspective. Please clarify that a BA has one and only one RC and adjust Part 3.2 accordingly. (10) INT-004-3 – R4 – This requirement is clearly a business practice and should be removed. Any requirement that directs a registered entity to comply with a NAESB business practice will in essence be a business practice itself. While it may be desirable for many reasons to comply with a NAESB business practice, it simply does not rise to the level of reliability requirement. If it did, then the Pseudo-Tie registry should be moved to NERC. (11) INT-004-3 - Native and Attaining BAs are used in the Guidelines and Technical Basis section. They should be included with this standard as a result. (12) INT-006-4 R1 – This requirement does not reflect the practical reality with how E-tags are generated and approved. It is this practical reality that obviates the need for the requirement. Any entity such as a PSE or LSE must have tagging software to create E-tags. In turn, BAs and TSPs have tagging software that they use to review and approve the E-Tags. When an LSE or PSE enters a request for interchange as an E-tag, that E-tag is essentially communicated to all entities that need to approve the E-tag at the same time. These software packages have become so entrenched, it would be impossible for a BA, TSP, LSE or PSE to enter into an interchange transaction or to review approve one without the software. Thus, the need for the requirement to have the Sink BA distribute the Arranged Interchange has been obviated with the entrenchment of the software. (13) INT-006 R1 – This requirement is not necessary because an interchange transaction is essentially business transaction. The only reliability component to the transaction is for the sending and receiving BAs to ensure they have equal but opposite interchange values and it is really only necessary to ensure this for the Composite Interchange Schedule and not each individual interchange schedule. (14) INT-006-4 Part 2.2 – Denying Arranged Interchange or curtailing Confirmed Interchange because the scheduling path is invalid is a business practice issue. While we agree that this is a necessary task to comply with open access transmission tariffs, it is not a reliability issue but rather a business practice issue. Furthermore, this is a validation that should be performed automatically with tagging software. Thus, this part should be removed. (15) INT-006-4 Part 3.1 - Denying Arranged Interchange because the transmission path is invalid is a business practice issue and is not a reliability issue. It provides no indication for whether the transmission system can handle the Arranged Interchange. This should be moved to a NAESB business practice. Furthermore, this is something that should be automatically handled via the tagging software and is obviated by the entrenched nature of the software. (16) INT-006-4 R5 – While we agree the timing tables provide an orderly structure for processing requests for interchange, Arranged Interchange and Confirmed Interchange, the simple reality is that the timing tables in Attachment 1 are a business practice and present the opportunity for zero-defect enforcement contrary to the reliability assurance initiative. Whether the sink BA distributes the Arranged interchange within one minute of receiving it is immaterial to reliability. If the sink BA takes two minutes to process Arranged Interchange and there is still ample time for all approvals to be given how is reliability harmed? If a BA and TSP take longer to perform their “reliability assessments” than the time allotted but the Arranged Interchange proceeds to Confirmed and then Implemented Interchange, how is reliability harmed? Some entities can literally process thousands of the Arranged Interchanges per month. Because no computer system can be expected to work perfectly all the time (consider that six sigma established maximum reliability levels at 99.99966% and most tagging software probably does not achieve this idealized reliability rate) , it is a guarantee that some Arranged Interchange will not be processed according to the timing tables for some Arranged Interchange. Thus, these timing tables should be moved to NAESB business practices. The binary nature of the VSLs continue to use the zero-defect compliance approach and should be modified as well. For each of the thousands of schedules that occur on the Interconnection each month, there is an opportunity for compliance violations due to the zero-defect approach to compliance. How does this support reliability? (17) INT-006-4 R6 – This part states that the Sink BA must distribute notifications of whether Arranged Interchange was transitioned to Confirmed Interchange per the timing tables. While we agree this approach is a structured and orderly way to process Arranged Interchange and communicate approvals and denials, it is again a business practice. Business practices should be moved to NAESB. Furthermore, the need for the requirement is obviated by entrenched tagging software that is necessary to implement Interchange. (18) INT-006-4 Part 6.4 – PSE has been replaced in many parts of the proposed modifications to the INT standards with LSE. Part 6.4 compels notification of approvals and denials to the PSE but there is no companion part to compel notification to the LSE. Is this intended? (19) INT-006-4 – Guideline and Technical Basis – The first main bullet on page 18 states that the LSE “that approves or denies Arranged Interchange”. The LSE does neither. The LSE submits a Request for Interchange that becomes Arranged Interchange once the appropriate reliability entities receive and approve the request. (20) INT-006-4 – Guideline and Technical Basis – The first sub-bullet under the second main bullet on page 18 refers to communication that occurs between BAs, TSPs and PSEs. This is not consistent with the remainder of the proposal which focuses on replacing PSEs with LSEs. (21) INT-009-2 R1 – Because this requirement references another standard, it creates the opportunity for double jeopardy and is vague and ambiguous. The requirement compels a BA to agree with its Adjacent BAs on Composite Confirmed Interchange “as directed per INT-010-2”. Either this requirement should stand alone or INT-010-2 should stand alone. They should not reference one another because any time INT-010-2 is violated, this requirement may likely be violated causing double jeopardy. The reference to INT-010-2 is vague as well. What specifically is directed in INT-010-2 that must be complied with in order to comply with INT-009-2 R1? (22) INT-009-2 R1 – This requirement is redundant with BAL-006-2 R4 which already requires Adjacent BAs to operate to a “common Net Interchange Schedule and Actual Net Interchange value” with opposite signs. Redundancy is one of the paragraph 81 criteria. Please remove the redundancy to avoid implementing requirements that will be retired later. (23) Request for Interchange definition – This definition uses the term Interchange inconsistent with the NERC definition. It states that a Request for Interchange may be a “bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority”. By NERC definition, Interchange is “Energy transfers that cross Balancing Authority boundaries”. Obviously, a Request for Interchange within a single Balancing Authority does not cross BA boundaries. (24) INT-010-2 R1 – There is an extraneous comma at the end of the requirement. (25) INT-010-2 R2

– We are not convinced this requirement is needed. The E-Tag specification already includes specific details about the Reliability Level associated with an E-Tag and how a reliability entity may in essence cap the energy flow at this level. Why is a separate NERC requirement needed? (26) INT-010-2 R1 and R3 – Because the practical reality is that Interchange cannot be implemented without utilizing tagging software, we question the need for these two requirements. Ensuring the interchange transactions are tagged essentially has become a business practice. (27) INT-010-2 R4 – Part 4.1 through Part 4.5 should be written as bullets and not numbered lists. Per a NERC filing to FERC, NERC has stated that numbered lists are utilized when each element of the list must be met while bullets are utilized when they are options and not everyone needs to be met. The lists seem to meet the latter more accurately. (28) INT-010-2 R6 – Requirement R6 uses the wrong term Reliability Adjusted Arranged Interchange. Reliability Adjusted Arranged Interchanged is a request and not confirmed or implemented and, thus, could be denied. Until confirmed and implemented, the BA should not control to this value. (29) INT-010-2 R6 – Requirement R6 potentially conflicts with IRO-006-EAST-1 R4. R4 allows alternate actions to be implemented rather than schedule reductions particularly if the schedule reductions will not be effective. INT-010-2 R6 seems to presume that congestion management tools such as the IDC and USF are surgically accurate and requires curtailments of Dynamic Schedules to be implemented as specified. The tools do have some inaccuracies and can result in curtailments that do not alleviate flows at times. Thus, R4 should allow alternate action such as re-dispatch similar to IRO-006-EAST-1 R4. (30) INT-011-1 does not support reliability and is simply a commercial equity issue and business practice. RCs, BAs, and TOPs are perfectly capable of working together to require a BA to re-dispatch its system without tagging these intra-BA transactions. In fact, FERC recognized that congestion management tools such as the IDC are not really reliability tools and required NERC to reflect this in the standards. IRO-006-EAST-1 R1 requires the RC to actually implement another action such as re-dispatch besides TLR to mitigate IROL exceedances. Thus, one can only conclude that standard is intended to ensure that congestion management procedures such as the IDC include these intra-BA transactions for commercial equity purposes. Even the purpose statement of the standard seems to reflect this in the statement intra-BA transfers utilizing Point-to-Point transmission service “are communicated and accounted for in congestion management procedures”. Thus, the purpose is ultimately a commercial equity issue to account for these transactions. Furthermore, the fact that it focuses on Point to Point transmission service shows that is a FERC tariff issue which is clearly about curtailing transmission service based on its priority. Tariff issues by definition are commercial equity and business issues. Please strike this entire standard. (31) Intermediate Balancing Authority – We disagree with the proposed definition. The proposed definition removes the requirement that this BA must be on the scheduling path. Please provide technical justification for why a BA not on the scheduling path would be considered an Intermediate BA. (32) Definitions – Please provide a technical justification for the need for the proposed changes to existing definition and a complete review of their use in the NERC standards. We need absolute clarity that modifying these existing definitions will not impact the meaning of other standard negatively. Until this is completed, we cannot support these proposed changes. (33) Composite Confirmed Interchange - Based on the use of Composite Confirmed Interchange in INT-009-2 R1, we

believe that this is intended to be the Interchange in aggregate between two BAs and not a single BAs net interchange. Please clarify the definition accordingly. Otherwise, the definition could be interpreted to be Net Scheduled Interchange for a single BA. (34) We believe the proposed modification to the definition of OPA is unnecessary. The definition includes expected generation output levels. How could expected generation output levels not include the impact of Interchange? It is included implicitly. (35) Paragraph 81 Comment Review – The matrix of comments regarding paragraph 81 project comments appears to be missing a significant number of comments. It would appear only six commenters commented on retiring INT standards per paragraph 81. This seems too low. (36) Thank you for the opportunity to comment.
Group
SPP Standards Review Group
Robert Rhodes
We take note of the inclusion of a tagging requirement for Pseudo-Ties that currently does not exist and wonder what has led the drafting team to reach this conclusion. We also wonder if this change will result in significant reliability improvements worthy of the extra effort needed to implement the change. That being the case, we could support the exclusion of Pseudo-Ties from the tagging requirements in INT-004-3 and INT-009-2. INT-004-3 We have concern with including requirements (R4) that are dependent upon the existence of a registry in NAESB that currently doesn't exist. How will we be notified when the registry is implemented and how can we be assured that we will be given adequate time to make the proper submittals? We wonder why R4 was even included in the draft INT-004-3 given this situation. There was no explanation given as to what the drivers were for making the definition changes to several key terms. Could the drafting team please provide some reasoning here, especially regarding the replacement of Interchange Transaction Tag with Request for Interchange? Replace 'real time' with 'Real-time' in the definitions of Dynamic Schedule and Pseudo-Tie. The latter is in the NERC Glossary of Terms. Make the same change in Requirement 3.1. In Section 5. Background, delete the 'that' at the end of the 4th line in the first bullet. Insert 'when' in M4 such that it reads: The Balancing Authority shall have evidence (…) that it only approved a Pseudo-Tie Arranged Interchange when the Pseudo-Tie is registered in the NAESB Electric Industry Registry. Reword the Severe VSL for R3 such that it reads: The Balancing Authority approved a Pseudo-Tie Arranged Interchange for a Pseudo-Tie and neither Part 3.1 nor Part 3.2 were met. In the Guidelines and Technical Basis Section in the Application Guidelines, be sure that Dynamic Schedule and Pseudo-Tie are capitalized properly. In the table in the Application Guidelines, capitalize Frequency Bias. It is a NERC defined term. Also, shouldn't consideration be given to manual load shedding outside of an EEA event which is included in the table? INT-006-4 Adjacent Balancing Authority is listed in the Definition of Terms Section but it is the same definition as that in the NERC Glossary of Terms. Why is it listed? Shouldn't it be removed? Replace the 'or' with an 'and' in the 4th line of M4. INT-009-2 Insert 'and Pseudo-Ties' following Dynamic Schedules in the 3rd line of M1. Also make this same insertion in the Severe VSL for R1. Replace the 'the' in front of HVDC tie with an 'an' in the 1st line of R3 and the last

line of M3. Also make this same change in the Severe VSL for R3. INT-010-2 Capitalize real-time in Requirement 4.5 and in M4.
Individual
Alice Ireland
Xcel Energy
Agree
MISO
Group
Western Electricity Coordinating Council
Steve Rueckert
INT-004-3, R2: Sub requirements should not have requirements under it. seems like 2.1.1 and 2.2.1 can be deleted because R2 already says that the updates should be made for future hours. INT-004-3, R3 and R4: Rationale for R3 says it will be effective until NAESB registry accepts Pseudo-Tie registrations. Rationale for R4 says it will become effective once the NAESB registry accepts Pseudo Tie registrations. Nothing in the standard under implementation/effective date indicates that R3 and R4 will not be effective at the same time. Suggestion would be to remove R3 and move the implementation date to once NAESB registry accepts pseudo tie registration. As written, it appears that R3 and R4 will be effective at the same time. INT-006-4, R1: Reference to other requirements in 1.1 makes it confusing. R1 appears to have two requirements. Consider splitting into two separate requirements. INT-006-4, R2: Reference to another requirement makes the language confusing.
Group
Bonneville Power Administration
Jamison Dye
BPA supports NERC's decision to retire INT-001-3; INT-003-3; INT-005-3; INT-007-1 and INT-008-3 and NERC's proposed changes in the following Standards INT-009-2; INT-010-2 and INT-011-1. BPA has comments and concerns regarding the two INT standards below. INT-004-3; Dynamic Transfer Definitions of Terms Used in Standard BPA suggests adding proposed new definitions in this section: Attaining Balancing Authority and Native Balancing Authority. Purpose Statement BPA agrees with the Purpose statement change. However, the Purpose statement is not updated in the INT-004-3 draft as identified in the Summary of Revisions (e.g., “tool” rather than “procedures” plus the cited examples). Background In 1st bullet - R1 does not originate from INT-004-2, but rather from INT-001-3. R2 should not be referenced in this 1st bullet. BPA suggests the 1st bullet to read, “R1 is modified from INT-001-3 to incorporate requirements….” In 2nd bullet - BPA suggests the 2nd bullet to read, “R2 is modified from INT-004-2 to separate….” Requirements and Measures Will the text boxes for R2 and R3 be moved to the Application Guidelines section of the Standard INT-004-3, when it has received its ballot approval? BPA supports R3 and R4 additions. When this Standard becomes final, BPA suggests the “effective statements” found in the Rationale boxes be retained within the Standard.

Application Guidelines “Table 1” reference in last paragraph (on page 11) has no “Table 1” labeled in the document. Either label the subsequent table “Table 1” or just reference “table below”. INT-006-4; Evaluation of Interchange Transactions 1) This INT standard states that rather than the Interchange Authority Service, the Sink BA is now responsible for sending the approval request to all Approval Entities applicable to the Arranged Interchange. The Sink BA is also responsible for collecting and compiling all approval responses and communicating the final state back out to the entities involved. In the west, these communication actions are currently conducted via WIT. Would this proposed INT result in any system or protocol changes in the west or would WIT still be used as it is today to provide these communications on behalf of the Sink BA? 2) BPA would like the drafting team to clarify the change made to timing tables that are applicable to WECC. The current NAESB timing tables have column "B" titled "The GPS, LSE, and PSE Conduct Market Assessment" however the timing table presented in INT-006 changes the title of the column to "BA and TSP Conduct Reliability Assessments". Our concern is that the timing tables appear to no longer be applicable to the Market Operators; GPS, LSE, or PSE's. As one of these entities, we exercise our review and approval rights on e-Tags each day. BPA believe that it is both helpful and appropriate for the timing tables to detail the amount of review time not only for BA's and TSP's but for GPE, LSE, and PSE's. We would request that the drafting team review the timing table and determine if another change to the column heading is appropriate or if the addition of a new column addressing the timing assessments for GPE, LSE, and PSE will resolve our concerns. Thank you for the opportunity to comment.

Consideration of Comments

Project 2008-12 Coordinate Interchange Standards

The Project 2008-12 drafting team thanks all commenters who submitted comments on the appropriate disposition of requirements in the current approved INT standards that were identified by stakeholders as candidates for consideration under criteria developed by the Paragraph 81 drafting team. The proposed draft INT standards, a mapping document showing the proposed disposition of requirements from the current approved standards as well as a summary of the proposed revisions, a list of comments received on the INT standards during Phase 1 of Paragraph 81, and the additional supporting documents were posted July 25, 2013 through August 23, 2013. Stakeholders were asked to provide input through a special electronic comment form. There were 29 responses, including comments from approximately 100 different people from approximately 68 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

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, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Russel Mountjoy	MRO NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayliegh Wilkerson	Lincoln Electric System	MRO	1, 5, 6
6.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
7.	Joseph DePoorter	Madision Gas and Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	Midcontinent Independent System Operator	MRO	2

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
					1	2	3	4	5	6	7	8	9	10
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6										
12.	Scott Bos	Muscatine Power and Water`	MRO	1, 3, 5, 6										
13.	Scott Nickels	Rochester Public Utilities	MRO	4										
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6										
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6										
16.	Tony Edleman	Nebraska Public Power District	MRO	1, 3, 5										
2.	Group	Guy Zito	Northeast Power Coordinating Council											X
	Additional Member	Additional Organization	Region	Segment Selection										
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10										
2.	Greg Campoli	New York Independent System Operator	NPCC	2										
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1										
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1										
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10										
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5										
7.	Kathleen Goodman	ISO - New England	NPCC	2										
8.	Michael Jones	National Grid	NPCC	1										
9.	Mark Kenny	Northeast Utilities	NPCC	1										
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1										
11.	Christina Koncz	PSEG Power LLC	NPCC	5										
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2										
13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10										
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9										
15.	Bruce Metruck	New York Power Authority	NPCC	6										
16.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5										
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10										
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1										
19.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1										
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5										
21.	Brian Robinson	Utility Services	NPCC	8										
22.	Brian Shanahan	National Grid	NPCC	1										
23.	Wayne Sipperly	New York Power Authority	NPCC	5										
24.	Donald Weaver	New Brunswick System Operator	NPCC	2										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
25.	Ben Wu	Orange and Rockland Utilities	NPCC 1										
26.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC 3										
3.	Group	Sammy Roberts	SERC OC Review Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Skiba	MISO	SERC	2
2.	Daniel Hawk	LG&E/KU	SERC	1, 3, 5, 6
3.	Wayne Van Liere	LG&E/KU	SERC	1, 3, 5, 6
4.	Bob Thomas	IMEA	SERC	4
5.	William Berry	OMU	SERC	3
6.	James Case	Entergy	SERC	1, 3, 6
7.	Robert Scott Homberg	TVA	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporaton	RFC	1
2.	Annette Bannon	PPL Susquehanna, LLC	RFC	5
3.		PPL Montana, LLC	WECC	5
4.		PPL Generation, LLC	RFC	5
5.	Elizabeth Davis	PPL EnergyPlus, LLC	NPCC	6
6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6
10.			MRO	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Randi Heise	NERC Compliance Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Connie Lowe	Dominion	RFC	5, 6
2.	Louis Slade	Dominion	SERC	1, 3, 5, 6
3.	MIke Garton	Dominion	NPCC	5, 6
4.	Randi Heise	Dominion	MRO	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Sasa Maljukan	Hydro One Networks Inc.	X		X							

	Additional Member	Additional Organization	Region	Segment Selection

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

1.	David Kiguel	Hydro One Networks Inc.	NPCC	1, 3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
2.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
3.	Dave Millam	Kansas City Power & Light	SPP	1, 3, 5, 6
4.	Kevin Nincehelser	Westar Energy	SPP	1, 3, 5, 6
5.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
6.	Susan Quinn	Westar Energy	SPP	1, 3, 5, 6
7.	Buck Reuter	Westar Energy	SPP	1, 3, 5, 6
8.	Marc Welsh	Westar Energy	SPP	1, 3, 5, 6
9.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Suzie Stone	Trans Commercial System Mgmt	WECC	1
2.	Wes Hutchison	Trans Commercial System Mgmt	WECC	1
3.	Mary Willey	Trans Commercial System Mgmt	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Individual	Kelly Cumiskey	PacifiCorp	X		X		X	X				
11.	Individual	Pamela Hunter	Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	X		X		X	X				
12.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
13.	Individual	Raj Hundal	Powerex						X				
14.	Individual	Nazra Gladu	Manitoba Hydro	X				X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
15.	Individual	Shari Heino	Brazos Electric Power Coop	X				X					
16.	Individual	Ed Skiba	MISO		X								
17.	Individual	Michael Falvo	Independent Electricity System Operator		X								
18.	Individual	Chris Nebrigich	Idaho Power Co.										
19.	Individual	Michael Lowman	Duke Energy	X		X		X	X				
20.	Individual	John Bee	Exelon and its' Affiliates	X		X		X					
21.	Individual	Kathleen Goodman	ISO New England Inc.		X								
22.	Individual	Michelle R. D'Antuono	Occidental Power Services Inc.			X							
23.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
24.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
25.	Individual	Bob Thomas, and Alice Schum	Illinois Municipal Electric Agency				X						
26.	Individual	Richard Vine	California Independent System Operator		X								
27.	Individual	Oliver Burke	Entergy Services, Inc.	X									
28.	Individual	Silvia P. Mitchell	NextEra Energy	X		X		X	X				
29.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Comments of "Entity Name"
Xcel Energy	MISO
Hydro One Networks Inc.	NPCC RSC
South Carolina Electric and Gas	SERC OC Review Group
Illinois Municipal Electric Agency	SERC OC Review Group, and MISO
Brazos Electric Power Coop	ACES
ISO New England Inc.	we agree with NPCC RSC members comments and offer additional input as well.

1. **Paragraph 81 Considerations: The Coordinate Interchange SDT (CISDT) has reviewed all of the previously posted INT standards, along with stakeholder feedback on the INT standards from Phase 1 of the Paragraph 81 project, as well as outstanding FERC directives assigned to the Coordinate Interchange project. The CISDT believes that all of the requirements remaining in the four standards that are being posted are necessary and require accountability. Please review the mapping document and the list of Paragraph 81 recommendations provided to the INT team as a result of comments received from stakeholders during Phase 1 of Paragraph 81, along with the proposed revisions to the INT standards. If you believe that a specific requirement in the proposed INT-004-3, INT-006-4, INT-009-2, INT-010-2, or INT-011-1 could be better addressed through alternate means than a NERC Reliability Standard, please provide the specific standard and requirement number, along with a specific suggestion for an alternate means to ensure the intended action is accomplished. Some examples of alternate means could include working with NAESB to incorporate the requirement into NAESB business practice standards; moving the requirement into the Guideline and Technical Basis section of the same standard; or working with a technical committee to develop a NERC guideline. Please be as specific as possible.**

Summary Consideration: **The Coordinate Interchange Standard Drafting Team posted drafts of INT-004-3, INT-006-4, INT-009-2, INT-010-2, and INT-011-1 for a 30-day public comment period from July 25 – August 23, 2013. The posting was designed to gather stakeholder feedback regarding the proposed requirements, especially with respect to Paragraph 81 criteria and the recommendations made in the Independent Expert Review of the NERC standards. The drafting team carefully reviewed all comments submitted during the comment period, along with previous Paragraph 81 comments[2] and Independent Expert Review recommendations[3], but there was not clear stakeholder consensus on which standards or requirements should be retired. Therefore, the drafting team considered each of the recommendations and comments and incorporated those that team found to improve the quality of the standards. Specifically, the team revised many**

[2] The Consideration of Comments document for Project 2013-02 Paragraph 81's August 3-September 4, 2012 comment period can be downloaded at http://www.nerc.com/pa/Stand/Project%20201302%20Paragraph%2081%20DL/Comment_Report_P81_090412_final_responses_for_posting.pdf.

[3] The Standards Independent Experts Review Project - Final Report can be downloaded at http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf, along with the Standards Independent Experts Review Project - Requirements Scoring Spreadsheet at http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_IERP_Requirements_Spreadsheet_August_29_2013.xls.

requirements and removed four requirements that were previously posted, largely consistent with the recommendations made in the Paragraph 81 comments and the Independent Expert Review.

INT-004

- **R1: An exception for Pseudo-ties that are already accounted for in congestion management tools was added and the detail on the MW amount to be included on the transaction was eliminated.**
- **R2: The requirement was revised to apply to only those LSEs that submitted and RFI per R1. The drafting team also simplified the language or R2.1 and R2.2 and R2.3.**
- **R3: This was removed as an interim registration process was determined to be unnecessary.**
- **R4: The requirement was modified to require entities to register Pseudo-Ties when the registration process is available in the NAESB Electric Industry Registry (EIR).**
- **The drafting team added general considerations for curtailment of dynamic transactions to the Guidelines and Technical Basis section of the standard.**

INT-006

- **R1: This requirement was removed. The entities to receive the transaction are included today in the eTag specification, Section 3.6.1.1.1. The timing requirement for the distribution of tags is removed from this standard, as they are currently included and expected to remain in the NAESB documentation.**
- **R2, R3: The drafting team revised the language for clarity.**
- **R4: The drafting team added the specific entities to perform the review.**
- **R5: No changes. These requirements direct that 'active' approval is required to transition to Confirmed Interchange; that if entities do not approve the transaction that it will not be transitions to Confirmed. If the software were not automatically performing this function, this requirement identifies the logic to be applied.**
- **R6: No changes. This distribution requirement may currently drive how software performs this function. However, if that software were not present this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the interchange to occur.**
- **Tables: The drafting team removed columns A and C details as these are no addressed in any requirement. These details remain in the NAESB timing tables.**

INT-009

- **R1: The drafting team added phrase "by a Reliability Coordinator" to clarify what aspect of INT-010 is applicable to this requirement.**
- **R2: No change was made to language but language was added to the Rationale.**
- **R3: This requirement was unchanged and was not removed as suggested by some commenters. Since the Transmission Operator is not a part of the approval process for the Interchange, this requirement is the only means by which they are aware of the need to adjust the HVDC flow.**

INT-010

- **R1: This language was modified to be consistent with the currently effective requirement. This results in minimal revision to the existing, enforceable requirement.**
- **R2, R3: The drafting team revised the term "created" to "submitted".**
- **R4: The drafting team agreed with comments that these are rules for when reliability adjusts should be used and if reliability adjusts were issued for reasons other than this it would not impact reliability. We agree these would be included in the NAESB business and the requirement is removed from the standard.**
- **R5: The entities to receive the transaction for evaluation are included today in the eTag specification, Section 3.6.1.1.1 so the drafting team has removed this requirement.**
- **R6: Pseudo-ties were added to the requirement and the language was clarified.**
- **The drafting team added general considerations for curtailment of dynamic transactions to the Guidelines and Technical Basis section of the standard.**

Several entities from the ERCOT area requested exemption from some or all of the standards. When the drafting team reviewed the requirements we did not see that an exemption is required. For example, on INT-011, if ERCOT does not have point-to-point service, the requirement would not apply and an exemption is not needed. However, when we look at INT-006, if ERCOT is involved in a transaction outside its area, all of these requirements would apply.

Organization	Question 1 Comment
ACES Standards Collaborators	(1) In general, most of the requirements in the INT standards either are business practices or steps that occur in tagging software that do little if anything to support reliability and there are only a few basic things that need to occur with Interchange to support reliability. First, tagging dynamic schedules and pseudo ties and intra-BA transactions are commercial equity issues intended to ensure these transactions are curtailed equitably with other transmission service. RC, BAs and TOP can always re-dispatch (which is essentially all a transmission service curtailment is) in other ways. The whole purpose of the IDC and WECC USF is to ensure transmission service is curtailed equitably and in an organized fashion. If commercial equity was not an issue these tools would not exist. Second, many of the requirements dealing with distributing Arranged and Confirmed Interchange are in fact software tool application and not necessary. Third, the adjacent BAs must agree to a common interchange number with equal value but opposite sign. This would include ensuring that dynamic transfers are accounted for correctly in either scheduled interchange or actual interchange and utilizing a common meter point. Technically, the interchange could even be wrong as long as both BAs are controlling to the same number but opposite in sign which avoids frequency deviation. While we would agree it is advantageous to build the interchange values from individual interchange schedules, from a reliability point of view, it is not necessary. However, these steps really boil down to accounting for each transaction, the ownership, energy imbalance, and various sundry of other commercial equity concerns. Thus, each schedule essentially represents a business transaction and is accounted for separately to facility business processing and making it easier to identify errors in interchange. Second, the BAs must ensure that they can support the magnitude of the Interchange including the ramping capability. Third, the transmission system must be able to support the transaction. However, from a practical perspective, the only check that is performed here is to ensure that a valid transmission service reservation is utilized and not overrun. Failing to allow Arranged Interchange that utilizes a perfectly valid transmission

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	service reservation to proceed to Confirmed and Implemented Interchange could be viewed as a tariff violation unless there is an imminent transmission threat (i.e. violated IROL). The Arranged Interchange could be utilizing a higher priority transmission service reservation that will bump other Implemented Interchange that utilizes lower priority transmission service. In essence, the request is submitted to re-allocate transmission service to the highest priority through tools such as the IDC. Thus, most TSPs are reluctant to not allow Arranged Interchange to transition to Confirmed Interchange due to transmission constraints.(2) We disagree with requiring Dynamic Schedules and Pseudo-Ties to be tagged in a reliability standard (INT-004-3). The purpose of tagging these schedules is a commercial equity issue. By NERC definition (both proposed and existing), a Dynamic Schedule is already correctly implemented in both the Attaining and Native Balancing Authorities. Thus, load, generation, and interchange will be balanced. Thus, the only reliability concern that is left is if the transmission system can handle the Dynamic Schedule. Since the vast majority of these Dynamic Schedules are grandfathered and, those, that are not will utilize firm transmission, the transmission system can certainly handle these Dynamic Schedules. This means that the only issue left is that it is a commercial equity and transparency issue. Because it has been historically recognized that these transactions will be accommodated on the transmission system in all but the rarest cases, years ago, market participants recognized that if these transaction were not tagged and firm transmission was curtailed, these transaction would not receive any curtailment. At that time, market participants held seats on NERC groups such as the Operating Reliability Subcommittee and insisted on these transactions being tagged for fairness. This means it is a business practice and rightfully belongs in a NAESB standard. Even the purpose statement of the standard is clear that the purpose is to ensure that the transactions are accounted for in congestion management procedures appropriately. This is not a reliability concern and it should be transitioned to a NAESB business practice.(3) Congestion management procedures (such as the IDC and WECC USF) cannot be viewed as primarily reliability tools and, thus, tagging transactions is essentially a commercial equity issue to ensure fair and non-discriminatory transmission service. Rather these tools are implemented to help ensure an orderly prioritization of transmission service. They help ensure that only those transactions with a

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	significant impact are curtailed on a flowgate or transfer path and that the lowest priority transmission service is curtailed first. They also help to reallocate flows when higher priority transmission is scheduled on an already congested flowgate or transfer path. FERC has held in Order No. 693 that congestion management tools such as the IDC in essence are not reliability tools by refusing to allow them to be the only tool used to unload a flowgate experiencing an IROL exceedance. IRO-006 reflects this. NERC's CEO recently supported this position at the August 2013 NERC BOT meeting in Montreal when he stated the reason NERC no longer supports the IDC is because it is a congestion management tool and not a reliability tool. We strongly recommend the review team eliminate all non-reliability concepts from the INT standards.(4) INT-004-3 - The reliability impact of Dynamic Schedules will be addressed appropriately in the agreement established between the Attaining and Native BAs. The agreement will include items such as common metering points, implementation dates, testing requirements, etc. No additional reliability standards requirements are necessary for Dynamic Schedules. A NERC reliability guideline might be appropriate to identify what should be in these agreements and how to implement a Dynamic Schedule successfully.(5) Only the definition for Dynamic Schedule is proposed to be modified. Dynamic Interchange Schedule is also defined the same as Dynamic Schedule. If the drafting team is proposing to eliminate Dynamic Interchange Schedule this should be stated clearly or it should also be included in the definition. If it will be retired, all standards should be reviewed to ensure it is not use elsewhere. (6) INT-004-3 R2 - The "is reviewed" should be modified in the standard. The checks that must occur to move Arranged Interchange to Confirmed Interchange could be viewed as a review. Thus, we suggest that the wording should state more directly what is required. The energy profile is to be compared against the actual energy flow. (7) INT-004-3 Part 2.3 - This could be stated more simply. If the RC or TOP instructs the LSE to update the tag, they should. (8) INT-004-3 R3 - This is clearly a business practice as stated in the rationale box and implementation plan. The requirement is expected to be implemented in a NAESB standard. This makes it clear this is a business practice and we cannot support this as reliability standard requirement enforceable by sanctions. (9) INT-004-3 - Part 3.2 implies that a BA can have more than one reliability coordinator. We do not believe this is possible from a practical

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	perspective. Please clarify that a BA has one and only one RC and adjust Part 3.2 accordingly. (10) INT-004-3 - R4 - This requirement is clearly a business practice and should be removed. Any requirement that directs a registered entity to comply with a NAESB business practice will in essence be a business practice itself. While it may be desirable for many reasons to comply with a NAESB business practice, it simply does not rise to the level of reliability requirement. If it did, then the Pseudo-Tie registry should be moved to NERC.(11) INT-004-3 - Native and Attaining BAs are used in the Guidelines and Technical Basis section. They should be included with this standard as a result. (12) INT-006-4 R1 - This requirement does not reflect the practical reality with how E-tags are generated and approved. It is this practical reality that obviates the need for the requirement. Any entity such as a PSE or LSE must have tagging software to create E-tags. In turn, BAs and TSPs have tagging software that they use to review and approve the E-Tags. When an LSE or PSE enters a request for interchange as an E-tag, that E-tag is essentially communicated to all entities that need to approve the E-tag at the same time. These software packages have become so entrenched, it would be impossible for a BA, TSP, LSE or PSE to enter into an interchange transaction or to review approve one without the software. Thus, the need for the requirement to have the Sink BA distribute the Arranged Interchange has been obviated with the entrenchment of the software.(13) INT-006 R1 - This requirement is not necessary because an interchange transaction is essentially business transaction. The only reliability component to the transaction is for the sending and receiving BAs to ensure they have equal but opposite interchange values and it is really only necessary to ensure this for the Composite Interchange Schedule and not each individual interchange schedule.(14) INT-006-4 Part 2.2 - Denying Arranged Interchange or curtailing Confirmed Interchange because the scheduling path is invalid is a business practice issue. While we agree that this is a necessary task to comply with open access transmission tariffs, it is not a reliability issue but rather a business practice issue. Furthermore, this is a validation that should be performed automatically with tagging software. Thus, this part should be removed. (15) INT-006-4 Part 3.1 - Denying Arranged Interchange because the transmission path is invalid is a business practice issue and is not a reliability issue. It provides no indication for whether the transmission system can handle the Arranged Interchange. This should be moved to a NAESB

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	business practice. Furthermore, this is something that should be automatically handled via the tagging software and is obviated by the entrenched nature of the software. (16) INT-006-4 R5 - While we agree the timing tables provide an orderly structure for processing requests for interchange, Arranged Interchange and Confirmed Interchange, the simple reality is that the timing tables in Attachment 1 are a business practice and present the opportunity for zero-defect enforcement contrary to the reliability assurance initiative. Whether the sink BA distributes the Arranged interchange within one minute of receiving it is immaterial to reliability. If the sink BA takes two minutes to process Arranged Interchange and there is still ample time for all approvals to be given how is reliability harmed? If a BA and TSP take longer to perform their “reliability assessments” than the time allotted but the Arranged Interchange proceeds to Confirmed and then Implemented Interchange, how is reliability harmed? Some entities can literally process thousands of the Arranged Interchanges per month. Because no computer system can be expected to work perfectly all the time (consider that six sigma established maximum reliability levels at 99.99966% and most tagging software probably does not achieve this idealized reliability rate) , it is a guarantee that some Arranged Interchange will not be processed according to the timing tables for some Arranged Interchange. Thus, these timing tables should be moved to NAESB business practices. The binary nature of the VSLs continue to use the zero-defect compliance approach and should be modified as well. For each of the thousands of schedules that occur on the Interconnection each month, there is an opportunity for compliance violations due to the zero-defect approach to compliance. How does this support reliability?(17) INT-006-4 R6 - This part states that the Sink BA must distribute notifications of whether Arranged Interchange was transitioned to Confirmed Interchange per the timing tables. While we agree this approach is a structured and orderly way to process Arranged Interchange and communicate approvals and denials, it is again a business practice. Business practices should be moved to NAESB. Furthermore, the need for the requirement is obviated by entrenched tagging software that is necessary to implement Interchange.(18) INT-006-4 Part 6.4 - PSE has been replaced in many parts of the proposed modifications to the INT standards with LSE. Part 6.4 compels notification of approvals and denials to the PSE but there is no companion part to compel notification to the LSE. Is this

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	intended? (19) INT-006-4 - Guideline and Technical Basis - The first main bullet on page 18 states that the LSE "that approves or denies Arranged Interchange". The LSE does neither. The LSE submits a Request for Interchange that becomes Arranged Interchange once the appropriate reliability entities receive and approve the request. (20) INT-006-4 - Guideline and Technical Basis - The first sub-bullet under the second main bullet on page 18 refers to communication that occurs between BAs, TSPs and PSEs. This is not consistent with the remainder of the proposal which focuses on replacing PSEs with LSEs. (21) INT-009-2 R1 - Because this requirement references another standard, it creates the opportunity for double jeopardy and is vague and ambiguous. The requirement compels a BA to agree with its Adjacent BAs on Composite Confirmed Interchange "as directed per INT-010-2". Either this requirement should stand alone or INT-010-2 should stand alone. They should not reference one another because any time INT-010-2 is violated, this requirement may likely be violated causing double jeopardy. The reference to INT-010-2 is vague as well. What specifically is directed in INT-010-2 that must be complied with in order to comply with INT-009-2 R1?(22) INT-009-2 R1 - This requirement is redundant with BAL-006-2 R4 which already requires Adjacent BAs to operate to a "common Net Interchange Schedule and Actual Net Interchange value" with opposite signs. Redundancy is one of the paragraph 81 criteria. Please remove the redundancy to avoid implementing requirements that will be retired later. (23) Request for Interchange definition - This definition uses the term Interchange inconsistent with the NERC definition. It states that a Request for Interchange may be a "bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority". By NERC definition, Interchange is "Energy transfers that cross Balancing Authority boundaries". Obviously, a Request for Interchange within a single Balancing Authority does not cross BA boundaries. (24) INT-010-2 R1 - There is an extraneous comma at the end of the requirement. (25) INT-010-2 R2 - We are not convinced this requirement is needed. The E-Tag specification already includes specific details about the Reliability Level associated with an E-Tag and how a reliability entity may in essence cap the energy flow at this level. Why is a separate NERC requirement needed? (26) INT-010-2 R1 and R3 - Because the practical reality is that Interchange cannot be implemented without utilizing tagging software, we question the need

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	for these two requirements. Ensuring the interchange transactions are tagged essentially has become a business practice. (27) INT-010-2 R4 - Part 4.1 through Part 4.5 should be written as bullets and not numbered lists. Per a NERC filing to FERC, NERC has stated that numbered lists are utilized when each element of the list must be met while bullets are utilized when they are options and not everyone needs to be met. The lists seem to meet the latter more accurately. (28) INT-010-2 R6 - Requirement R6 uses the wrong term Reliability Adjusted Arranged Interchange. Reliability Adjusted Arranged Interchanged is a request and not confirmed or implemented and, thus, could be denied. Until confirmed and implemented, the BA should not control to this value.(29) INT-010-2 R6 - Requirement R6 potentially conflicts with IRO-006-EAST-1 R4. R4 allows alternate actions to be implemented rather than schedule reductions particularly if the schedule reductions will not be effective. INT-010-2 R6 seems to presume that congestion management tools such as the IDC and USF are surgically accurate and requires curtailments of Dynamic Schedules to be implemented as specified. The tools do have some inaccuracies and can result in curtailments that do not alleviate flows at times. Thus, R4 should allow alternate action such as re-dispatch similar to IRO-006-EAST-1 R4. (30) INT-011-1 does not support reliability and is simply a commercial equity issue and business practice. RCs, BAs, and TOPs are perfectly capable of working together to require a BA to re-dispatch its system without tagging these intra-BA transactions. In fact, FERC recognized that congestion management tools such as the IDC are not really reliability tools and required NERC to reflect this in the standards. IRO-006-EAST-1 R1 requires the RC to actually implement another action such as re-dispatch besides TLR to mitigate IROL exceedances. Thus, one can only conclude that standard is intended to ensure that congestion management procedures such as the IDC include these intra-BA transactions for commercial equity purposes. Even the purpose statement of the standard seems to reflect this in the statement intra-BA transfers utilizing Point-to-Point transmission service “are communicated and accounted for in congestion management procedures”. Thus, the purpose is ultimately a commercial equity issue to account for these transactions. Furthermore, the fact that it focuses on Point to Point transmission service shows that is a FERC tariff issue which is clearly about curtailing transmission service based on its priority. Tariff issues by definition are commercial equity and

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	business issues. Please strike this entire standard.(31) Intermediate Balancing Authority - We disagree with the proposed definition. The proposed definition removes the requirement that this BA must be on the scheduling path. Please provide technical justification for why a BA not on the scheduling path would be considered an Intermediate BA. (32) Definitions - Please provide a technical justification for the need for the proposed changes to existing definition and a complete review of their use in the NERC standards. We need absolute clarity that modifying these existing definitions will not impact the meaning of other standard negatively. Until this is completed, we cannot support these proposed changes. (33) Composite Confirmed Interchange - Based on the use of Composite Confirmed Interchange in INT-009-2 R1, we believe that this is intended to be the Interchange in aggregate between two BAs and not a single BAs net interchange. Please clarify the definition accordingly. Otherwise, the definition could be interpreted to be Net Scheduled Interchange for a single BA. (34) We believe the proposed modification to the definition of OPA is unnecessary. The definition includes expected generation output levels. How could expected generation output levels not include the impact of Interchange? It is included implicitly. (35) Paragraph 81 Comment Review - The matrix of comments regarding paragraph 81 project comments appears to be missing a significant number of comments. It would appear only six commenters commented on retiring INT standards per paragraph 81. This seems too low. (36) Thank you for the opportunity to comment.
Manitoba Hydro	(5) INT-006-4, Application Guidelines - for consistency with other sections of the document, remove all the ‘periods’ from the end of the bullets listed in this guideline. (6) INT-009-2 - for consistency with the other INT standards, remove the ‘periods’ from the end of the bullets listed in this section. (7) INT-010-2 - for consistency with the other INT standards, remove all ‘periods’ from the end of all bullets listed in this standard. (8) INT-010-2, R1 - remove the comma at the end of R1. (10) INT-011-1 - add a period following the definition of Interchange Coordination. (11) INT-011-1, R1.1 - periods are inconsistently being utilized throughout this standard. Manitoba Hydro suggests adding or removing the period(s) from the end of all

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	sentences. (12) General Comment - replace “Board of Trustees” with “Board of Trustees’” throughout the applicable documents/standards for consistency with other standards. (13) INT-006-4, R4 - for reliability reasons the Reliability Coordinator would identify the curtailment and the best resolution from the big picture. If a BA denies the transaction the burden is shifted to the neighbors. Is there a better mechanism or language to resolve this problem? How do you police it? (14) Manitoba Hydro is in agreement with the language in INT-006-4, R5 & R6, but believes that clarity is needed in the Attachment 1 - Timing Table. How does a transaction start 1 hour after the start time?
Powerex	1. Paragraph 81 Considerations: The Coordinate Interchange SDT (CISDT) has reviewed all of the previously posted INT standards, along with stakeholder feedback on the INT standards from Phase 1 of the Paragraph 81 project, as well as outstanding FERC directives assigned to the Coordinate Interchange project. The CISDT believes that all of the requirements remaining in the four standards that are being posted are necessary and require accountability. Please review the mapping document and the list of Paragraph 81 recommendations provided to the INT team as a result of comments received from stakeholders during Phase 1 of Paragraph 81, along with the proposed revisions to the INT standards. If you believe that a specific requirement in the proposed INT-004-3, INT-006-4, INT-009-2, INT-010-2, or INT-011-1 could be better addressed through alternate means than a NERC Reliability Standard, please provide the specific standard and requirement number, along with a specific suggestion for an alternate means to ensure the intended action is accomplished. Some examples of alternate means could include working with NAESB to incorporate the requirement into NAESB business practice standards; moving the requirement into the Guideline and Technical Basis section of the same standard; or working with a technical committee to develop a NERC guideline. Please be as specific as possible. Comments on INT StandardsPowerex would like to thank the CISDT for their hard work in developing a more consolidated and concise version of the Interchange Standards, and respectfully submits the following comments for consideration.General Comments:Powerex has reviewed the latest draft of the Interchange Standards and considers

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	these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are important and prevent entities that transact from providing inaccurate information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is implemented in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations.Powerex believes that it is fundamentally important that all interchange be scheduled using e-Tags, and appropriately evaluated by the reliability entities listed on the e-Tag. Ensuring that all interchange transaction are e-Tagged allows reliability tools, such as NERC IDC and WECC webSAS, to effectively manage congestion through curtailment based on transmission priority. Powerex does not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards. Definitions: 1) The phrases “reliability events” or “reliability assessment” are not defined and are key concepts in these new standards. In INT-010-2 the language was changed to allow exemptions where reliability entities can modify or initiate schedules under abnormal Operating conditions. Now it allows those changes or new schedules to “address reliability events”. Powerex believes that these terms should be defined to remove any ambiguity within these standards. 2) The definition of Intermediate BA has been modified, but it is not clear as to why a new definition is required or why the old definition is inadequate? Further rationale on the changes in definitions would be useful for the industry in evaluating these standards.3) INT - 009 creates two new definitions for Attaining BA and Native BA. Is there a need to create these new definitions or could we use the currently defined NERC terms such as Sink or Receiving BA, and Source or Sending BA? Further rationale is required as to the reasons for the new definitions, and reasons for not using the current NERC definitions.4) INT - 009 modifies the definition of Confirmed Interchange. However, the definition only requires Sink BA to verify Arranged Interchange, but it should also state that the Sink BA has also verified that interchange has been approved by all BAs and TSP listed on the e-Tag.INT - 004 - Dynamic Transfer1) R1 as currently written is only

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	applicable to LSEs that use Dynamic Transfer to serve load, and is not applicable to any PSE that submits a Dynamic Transfer. Powerex believes that the standard should be applied to all entities that use Dynamic Transfers, whether it is used to serve load or provide imbalance service. The Dynamic Transfer, regardless of its intended use, has the same level of impact to the BES, and applying this requirement only to subset of all Dynamic Transfers would not meet the intent and purpose of this standard. 2) R1, the second bullet, we would suggest removing the word “expected”. It is counter-intuitive to suggest that we use the “expected maximum” in the situation where there is “no forecast”. Powerex prefers that the requirements be clear and the removal of “expected” would provide that clarity. 3) The standard is silent on the transmission requirements that would be used for the Dynamic Transfer. It is important that the transmission capacity required to support the transfer of dynamic flow be appropriately obtained, validated and verified prior to implementation. For example, dynamic schedules that are e-Tagged at an average MW level, but do not have sufficient transmission capacity above the average MW level may cause SOL exceedances when dynamic dispatches exceed the average MW indicated on the e-Tag. These types of scheduling issues result in cascading curtailments, which has impacts to other Generators and Loads that must accommodate as a result of the inaccurate scheduling of Dynamic Transfers. It is important that this standard clearly articulate that each dynamic transfer shall procure sufficient transmission to accommodate the maximum dynamic transfer. INT - 006 - Evaluation of Interchange1) There does not appear to be any requirement that prescribes at a minimum that an Interchange Transaction or Interchange Schedule must be submitted for energy that flows between Balancing Authorities. This should be the case and a new requirement should be developed to reflect this. Otherwise some entities may choose not to submit certain interchange transactions even though it may affect adjacent Balancing Authorities and TSPs.2) This standard must prescribe at a minimum the verification and validations that must be performed during the reliability assessment by a BA and TSP. Those minimum requirements should not be prescribed in the Technical Guidance section of the standard because they would not be considered mandatory and could be ignored by Responsible Entities. It is imperative that this standard provide clear requirements that ensure BA and TSP are validating impacts, and not

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	allowing transactions to flow that will cause issues within the interconnection. For example, a Source BA should validate and not allow a generator to schedule above and beyond its nameplate capacity to ensure accurate scheduling. Powerex believes that a Source BA will only perform these types of checks if there is a prescribed minimum requirement within a standard, and suggests that the CISDT provide the minimum set of validations. 3) A BA or TSP should deny an interchange that does not accurately provide information especially in relation to the possible BA generation and load. Eg. A generator scheduling 200 MW from a 100 MW nameplate should be actively monitored, verified and denied by BA and VRF/VSF should be established to ensure that BA administers that check. In addition to that BAs should also evaluate and determine if the interchange supports an actual load, and the exports from a Source BA do not exceed generation located in the BA. 4) R2 and R3 does not hold the BA or TSP accountable to correctly approve or deny the interchange request the first time, and allows the entities to rectify the issue through curtailment of the interchange. Powerex believes that these requirements should be modified to rectify a possible loophole that could lead to inefficient scheduling practices.5) M2 and M3 should measure the times the BA or TSP approves a request without proper verification or validation and then subsequently curtails the interchange once they realize the mistake. The BA or TSP should perform a thorough validation of an Arranged Interchange to avoid such instances which rectify BA or TSP mistakes. Powerex suggests that when a BA or TSP reevaluates a Confirmed Interchange that they note in the comments the reason for the reevaluation. 6) For Attachment 1, there should be a reference point for the time that constitutes whether or not an Arranged Interchange is "on-time" or not. The previous Standard (INT-006-3) used to have the second column of the Timing Requirements table labeled as "IA Assigned Time Classification". The new table heading for the second column is not assigned to an entity and states just "Time Classification". This will result in potential disputes as to who determines and classifies whether or not the RFI is "on-time". An Entity should be assigned the responsibility to determine the correct time classification (On-Time, Late, etc). Powerex suggests that the Sink BA be the Responsible Entity, and that once the Sink BA assigns a classification that other approval entities should respect that classification.INT - 010 - Modification of Interchange1) In R1, the term "energy sharing" is not

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	capitalized and thus is open to interpretation, and this leaves the door open for entities to submit RFIs after the scheduling deadlines. In the original INT-010-1, this issue was dealt with by describing the circumstance which this was allowed, specifically "...a loss of resources covered by an energy sharing agreement....". Either "energy sharing" needs to be defined, or the conditions to allow these modifications should be limited. Powerex suggests reverting back to the current INT-010-1 language use, "...a loss of resources covered by an energy sharing agreement....".2) R4.5 states that "Any real-time reliability concern" could lead to a Reliability Adjustment. Powerex believes that this requirement requires further clarification. Could the CISDT provide examples of other reliability concerns outside of R4.1 to R4.4 that would qualify for R4.5? Powerex is not aware of any other reliability concerns than the ones listed for R4.1 to R4.4, and suggests that R4.5 be modified to be more specific by providing details regarding the bounds or that R4.5 be removed entirely.3) R6 should also apply to Pseudo Ties and not just Dynamic Schedules. Powerex suggests that the language be revised to include Pseudo Ties or that a separate requirement be drafted to limit Pseudo Tie transfers when reliability limits are placed on the interchange.
City of Austin dba Austin Energy	Austin Energy (AE) requests that the SDT review the applicability of these standards in the ERCOT Region. Because ERCOT ISO is the only Balancing Authority in the ERCOT Interconnection, Dynamic Interchange from or to another Balancing Authority does not occur in the ERCOT Interconnection. AE requests the SDT make the applicability clear in the Applicability section using an approach similar to the MOD A project. Example text would be: 4.3 Exemptions: The following is exempt from INT-004-3. 4.3.1 Functional Entities operating in the ERCOT Region. AE believes this exemption is appropriate for all the INT standards in this posting, including the newly proposed INT-011-1.
Bonneville Power Administration	BPA supports NERC's decision to retire INT-001-3; INT-003-3; INT-005-3; INT-007-1 and INT-008-3 and NERC's proposed changes in the following Standards INT-009-2; INT-010-2 and INT-

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	011-1. BPA has comments and concerns regarding the two INT standards below. INT-004-3; Dynamic TransferDefinitions of Terms Used in StandardBPA suggests adding proposed new definitions in this section: Attaining Balancing Authority and Native Balancing Authority. Purpose Statement BPA agrees with the Purpose statement change. However, the Purpose statement is not updated in the INT-004-3 draft as identified in the Summary of Revisions (e.g., “tool” rather than “procedures” plus the cited examples).BackgroundIn 1st bullet - R1 does not originate from INT-004-2, but rather from INT-001-3. R2 should not be referenced in this 1st bullet. BPA suggests the 1st bullet to read, “R1 is modified from INT-001-3 to incorporate requirements....”In 2nd bullet - BPA suggests the 2nd bullet to read, “R2 is modified from INT-004-2 to separate....”Requirements and MeasuresWill the text boxes for R2 and R3 be moved to the Application Guidelines section of the Standard INT-004-3, when it has received its ballot approval? BPA supports R3 and R4 additions. When this Standard becomes final, BPA suggests the “effective statements” found in the Rationale boxes be retained within the Standard. Application Guidelines”Table 1” reference in last paragraph (on page 11) has no “Table 1” labeled in the document. Either label the subsequent table “Table 1” or just reference “table below”. INT-006-4; Evaluation of Interchange Transactions1) This INT standard states that rather than the Interchange Authority Service, the Sink BA is now responsible for sending the approval request to all Approval Entities applicable to the Arranged Interchange. The Sink BA is also responsible for collecting and compiling all approval responses and communicating the final state back out to the entities involved. In the west, these communication actions are currently conducted via WIT. Would this proposed INT result in any system or protocol changes in the west or would WIT still be used as it is today to provide these communications on behalf of the Sink BA? 2) BPA would like the drafting team to clarify the change made to timing tables that are applicable to WECC. The current NAESB timing tables have column "B" titled "The GPS, LSE, and PSE Conduct Market Assessment" however the timing table presented in INT-006 changes the title of the column to "BA and TSP Conduct Reliability Assessments". Our concern is that the timing tables appear to no longer be applicable to the Market Operators; GPS, LSE, or PSE's. As one of these entities, we exercise our review and approval rights on e-Tags each day. BPA believe that it is both helpful and

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	appropriate for the timing tables to detail the amount of review time not only for BA's and TSP's but for GPE, LSE, and PSE's. We would request that the drafting team review the timing table and determine if another change to the column heading is appropriate or if the addition of a new column addressing the timing assessments for GPE, LSE, and PSE will resolve our concerns. Thank you for the opportunity to comment.
Duke Energy	Duke Energy submits the following comments:INT-004The elimination of PSE in the Applicability Section of this standard and the associated requirements moves away from the NERC Functional Model. Duke Energy suggests a slight modification to R1, “ Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted by the PSE as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie at either:”Duke Energy believes that R3.2 should only include the RC. If a different Registered Entity is required, this issue should be addressed by a Regional Reliability Standard. INT-006 Duke Energy suggests replacing “Balancing Authority Area” with “Balancing Authority” for the definition of Adjacent Balancing Authority.Duke Energy would like for the SDT to consider adding a provision to R6 when scheduling systems are down, a move to a back-up control center, etc. These types of events could create a compliance risk with Attachment 1, Column D. Duke Energy also seeks clarification on the term “reliability assessments”. Who is responsible for conducting these “reliability assessments”? Per the functional model, TSPs do not conduct these types of assessments. Is it the intent of the SDT for the TSP to conduct a reliability assessment prior to approval of an Arranged Interchange? INT-009Duke Energy suggests changing the language in R1.2 to read, “Agree to the direction of the Composite Interchange with Adjacent Balancing Authority.”
Exelon and its' Affiliates	Exelon agrees with the rationale for INT-004 R3 and R4, but feels that they but fall short of a requirement for the BA or NAESB to periodically (annually at minimum) communicate the list of

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	Pseudo Tie lines within their zone to each Distribution Provider (DP) / Electric Distribution Company (EDC). Additionally, DPs/EDCs with no pseudo-ties in their zone should likewise be informed as well.Exelon would like to see the requirements address dynamic load that switches from LSE to LSE or from LSE to the Provider of Last Resort (POLR). The requirements should also address the situation of creating dynamic schedules for load at aggregate nodes. Exelon would like to see the order of the requirements in INT-004 changed from: R1, R2, R3, R4 to R3, R4, R1, R2 because we feel that proper registration of a Pseudo Tie Line must occur in order for requirements one and two to be effective. Finally, Exelon feels that there should be an exception to Violation Severity Levels for R1 and R2 in the situation where the Pseudo Tie Line was not properly registered by the BA in R3 and/or R4.INT-009-2 includes new definitions for Dynamic Schedule and Pseudo-Tie requiring that these values be treated as Interchange Schedules and Actual Interchange, respectively, and included in ACE equations. It is confusing, then, that R1 should specify that Composite Confirmed Interchange is to be calculated without inclusion of Dynamic Schedules and Pseudo-Ties. As Dynamic Transfers represent inputs to the ACE equation, and measurements against which a BA is managing its balancing function, to exclude them from the Composite Confirmed Interchange seems to paint an inaccurate picture of the Interchange between two Balancing Authorities. If the intention is to not skew Composite Arranged Interchange by the inclusion of values that change in Real Time with no settled value available until after-the-fact, that can be easily accomplished by stipulating that estimated values of Dynamic Schedules and Pseudo-Ties not be included in Composite Confirmed Interchange, and that the real-time values should be used for calculation of Composite Confirmed Interchange in the Real Time horizon, with the agreed on after the fact values used for calculation of Composite Confirmed Interchange in the after the fact horizon.
Northeast Power Coordinating Council	In general, these Standards represent the functions and actions necessary to effectively manage the details of interchange data. If this information were located in NAESB Business Practice Standards, which are the sources of the software specifications, and open to the industry for comment and voting, that would be adequate to serve reliability needs. Comments

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	by each individual Standard:INT-004For those entities that utilize dynamic transfers the transparency that the requirements provide is necessary for reliability.INT-006Requirements R1 and R6 can be removed (assuming the Standard is not retired) because they deal with given concepts of Arranged Interchange. INT-009BAL-005 Requirements R9 through R12 could be revised to incorporate the language/intent of these INT requirements. INT-009 would no longer be necessary. Regarding INT-009 R3, even though this requirement has been present since the original policy language was converted to Standards, it is an obvious function that is required in order for the flow to be set as desired. INT-010Requirements R1 through R3 are administrative to "document" the flow after the fact. This is good practice. These Requirements would be more appropriate in another Standard, possibly INT-011-1 Interchange Coordination Support. R4 is simply trying to enforce that entities don't use the "expedited" approval process for non-reliability reasons. A description in NAESB business practices would be adequate. R5 has reliability value in that an expedited process to have a curtailment approved is desirable. However, a RC can direct people to do something without the Tag. It is definitely needed in the software design to ensure the typical process of a curtailment is efficient. R6 is unnecessary because it is a qualifier for the operation of a dynamic schedule. If someone gets a Tag curtailment, that is their notice to adjust the source generation. They should not have to wait to get that direction (again) from somewhere else.
NERC Compliance Policy	In reviewing the INT standards associated with this Project, it would be helpful to have all impacting changes to the document redlined for review. Dominion suggests the SDT adopt the best practices of denoting the status of all changes rather requiring the reader to deduce the status from a range of statuses requiring additional research. For example, INT-011.1 includes a newly defined term identified as "This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here." Underlining added for emphasis.Dominion would like to state that in addition to INT-004-3, the revised definitions, "Dynamic Schedule" and "Pseudo-Tie" are also associated with reliability standards BAL-2-WECC-2 - Contingency Reserve, BAL-003-0.1b -

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	Emergency Response and Bias and BAL-005-0.2b - Automatic Generation Control, as noted in the Definitions of Terms Used in Standard section. Dominion believes that future instances of any change to a standard should be provided to the balloting body as red-line documents and noted for ease of modification identification and review. Dominion questions whether the word 'desires' in Requirement 1 should be replaced with 'is required'? We doubt that a PSE would desire to submit Requests for Interchange if it isn't required to do so. Dominion commends the SDT for concise mapping of the current requirements in the standards to the revised or relocated requirements.
Western Electricity Coordinating Council	INT-004-3, R2: Sub requirements should not have requirements under it. seems like 2.1.1 and 2.2.1 can be deleted because R2 already says that the updates should be made for future hours.INT-004-3, R3 and R4: Rationale for R3 says it will be effective until NAESB registry accepts Pseudo-Tie registrations. Rationale for R4 says it will become effective once the NAESB registry accepts Pseudo Tie registrations. Nothing in the standard under implementation/effective date indicates that R3 and R4 will not be effective at the same time. Suggestion would be to remove R3 and move the implementation date to once NAESB registry accepts pseudo tie registration. As written, it appears that R3 and R4 will be effective at the same time.INT-006-4, R1: Reference to other requirements in 1.1 makes it confusing. R1 appears to have two requirements. Consider splitting into two separate requirements.INT-006-4, R2: Reference to another requirement makes the language confusing.
Idaho Power Co.	INT-004-3: In R1 I have some concerns with the requirement to submit dynamic/pseudo schedules at the expected maximum MW profile if no forecast is available. Seems like this could create some confusion on what is considered a forecast. The transmisison is typically set at maximum and energy set at expected. Not sure if we need an option specifying what to tag if there is no forecast. I don't believe that R3 or R4 provide any reliability benefits to the Bulk Electric System. These Requirements could be addressed in another document. Also, I noticed

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	that several comments have stated that the industry should consider retiring all INT Standards and moving some if the requirements that impact reliability to the BAL Standards. I feel that there is value in retaining the INT Standards and not integrating them into the BAL Standards.
PPL NERC Registered Affiliates	INT-004-3The PPL NERC Registered Affiliates recommend removing language concerning Pseudo Ties from this Standard. It appears the R1 and R2 are attempting to require real-time hourly tags for Pseudo Tied loads. These Requirements would necessitate adjustments almost every hour to stay in compliance, creating the need for costly software, increased staff to manage, and extremely large tag files which will choke systems and existing reliable processes. The existing functionally in the IDC provides greater visibility, accountability, and more accurate data - all contributing to increased reliability. Also, Balancing Authorities are already aware of the effects of Pseudo Ties upon their systems because such effects are accounted for in their ACE equations. It is unclear what the technical justification is for requiring Pseudo Tied loads served by DNRs via NITS to use the Arranged Interchange process outlined in this Standard.Furthermore, we agree and support the SERC OC and MISO comments relating to tagging of Pseudo Ties in INT-004-3.
California Independent System Operator	INT-006At a minimum, R1 and R6 are the best candidates for removal, though all of INT-006 could be removed.To operate reliably, an entity needs only a net interchange with its neighbor. The details of what customer transactions make up that net interchange is commercial/financial. These requirements represent the functions and actions necessary to effectively manage the details of interchange data. If this information were located in a NAESB Business Practice Standards and the NAESB Electronic Tagging Functional Specification, which are the source of the software specifications, and is open to the industry for comment and voting, that would be adequate. INT-009BAL-005 R9-R12 could be modified to be clearer and incorporate the language/intent of these requirements. Thus, this Standard would no longer be necessary. When specifically reviewing R3, although this requirement has been present since

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	the original policy language was converted to standards; it is an obvious function that is required in order for the flow to be set as desired. This is comparable to generators needing to be told where to operate but there is no requirement for 'who' to notify them. INT-010R1-R3 are administrative to 'document' the flow after-the-fact. Real Time has already passed so it is not necessary for reliability. It is good practice to do these activities but they should be documented in best practices outside of the requirements.R4 is simply trying to enforce that entities don't use the 'expedited' approval process for non-reliability reasons. A description in NAESB business practices would be adequate. R5 may have some reliability value in that we desire an expedited process to have a curtailment approved. R6 is unnecessary because it is a qualifier for the operation of a dynamic schedule. If someone gets a Tag curtailment - that is their notice to adjust the source generation. INT-011INT-011 R.1 is needed to address the FERC directive identified in Order 693 (see Paragraph 817). Additionally, this directive was not one of the directives FERC suggested to withdraw in Notice of Proposed Rulemaking RM13-8-000 issued June 20, 2013.
Occidental Power Services Inc.	INT-011-1, Applicability Section and R1. The market structure and market operations of ERCOT renders R1 inapplicable. There is only one Balancing Authority within ERCOT (ERCOT itself) and, therefore, no intra-Balancing Authority Interchange. There is interchange across the DC ties between ERCOT and the Western and Eastern Interconnections, but this standard only applies to "intra-Balancing Authority areas." The Applicability Section should be revised to say "4.1.1. Load Serving Entities, except those in ERCOT."
NextEra Energy	NextEra Energy (including Florida Power & Light Company (FPL)) is registered for all functions, except Reliability Coordinator (RC), and FPL is the RC agent for the Florida Reliability Coordinating Council (FRCC). As such, NextEra has considerable experience with interchange, and, based on this experience it finds that all the Interchange Standards should be retired. There are a number of reasons that NextEra has come to this conclusion. One, all the

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	Interchange Standards meet the P81 criteria, including there is no reliability gap resulting from the retirement of the INT Standards. Second, NAESB already is regulating interchange via the e-tag system. Third, the independent expert's report supports the elimination of the Interchange Standards. Fourth, the few FERC outstanding directives issued on Interchange are outdated, and, therefore, should not impact the retirement of the Interchange Standards. In short, NextEra strongly recommends that the next posting of the INT Standards be focused on retiring all of the INT Standards.Interchange Standards meet the P81 criteria.The P81 criteria requires that both Criteria A and B be met to indicate that a Reliability Standard is appropriate to be retired.Criterion A of P81 states:The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "... operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."Interchange Standards do little to promote reliable operation, because: (i) as the independent expert report indicates all the interchange specifications are set forth in NAESB's e-tagging specifications and as well (ii) there is no correlation between the Interchange Standards and "operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system" do not occur. For those few aspects of Interchange Standards that are designed to ensure interchange is included in real-time monitoring and operations as well as situational awareness, these aspects are already covered in BAL-001, BAL-002, BAL-004, BAL-005, BAL-006, EOP-001, EOP-002, IRO-005, IRO-006, TOP-002, TOP-005. There are also WECC-specific interchange Standards and it is addressed in various MOD and TPL Standards. The INT Standards have become outdated, redundant administrative requirements that do little, if anything, to promote reliability. Thus, the Interchange Standards also meet Criteria B1 (administrative in nature), B3 (purely documentation), B6 (commercial or business practice) and B7 (redundant with other

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	requirements and NAESB). The current paradigm of Standards drafting, as set forth in the P81 criteria, as well and the independent expert's decision-trees, requires that the drafting team closely scrutinize the need for the INT Standards. NextEra views the INT Standards as providing no value and addressing no reliability gap. Accordingly, given the current approach to drafting Reliability Standards, the INT Standards should be retired as soon as possible. NextEra could go through each requirement and apply the above criteria, but for SMEs in this area, the application of the P81 criteria should be fairly straightforward. NextEra will send an SME to the next drafting team meeting to help the team focus on retiring requirements. Also, while the drafting team may believe it must have Standards to comply with certain Commission directives, these directives are outdated and with some education we believe the Commission will understand that interchange is more than sufficiently regulated via other Reliability Standards and NAESB.
PacifiCorp	PacifiCorp agrees that the proposed revisions should be addressed within the INT standards; however, there are several areas where the revisions are too broadly constructed and introduce a level of ambiguity that would make compliance with the INT standards challenging. PacifiCorp's concerns are highlighted below: o INT-004-3 R1 and R2: PacifiCorp does not believe there is a reliability benefit to the BES of requiring a Request for Interchange to be submitted as an on-time Arranged Interchange to the Sink Balancing Authority for a Pseudo-Tie. Pseudo-Tie tags do not calculate into any portion of the ACE and are used purely for accounting purposes. o INT-004-3 R3.2: PacifiCorp contends that for a BA's associated RC or TOP to confirm that "sufficient information" to reliably manage the Pseudo-Tie has been provided, it must first be clear what constitutes a "sufficient" amount of information. This language is too broad and subject to interpretation and is therefore difficult to measure. o INT-006-4 R2.2: PacifiCorp suggests the SDT change Balancing Authority to Intermediate Balancing Authority in order to clarify who is to complete the denial or curtailment. The Source and Sink Balancing Authorities are already required to perform this action under R2.1. o INT-006-4 R3.1: PacifiCorp suggests that that SDT expand the description of the "transmission path" to describe

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	other criteria beyond “proper connectivity of adjacent TSPs” such as sufficient OASIS rights, energy profile, physical path, and transmission profile. o INT-006-4 R4: PacifiCorp is uncertain of the reliability benefit of the Balancing Authority communicating a denial to the Reliability Coordinator after the fact and seeks justification from the drafting team. A denial reason is required on the e-Tag which should serve as proper notification. o INT-009-2: o R1: PacifiCorp seeks further clarification of the defined term, “Composite Confirmed Interchange.” Specifically with respect to how Composite Confirmed Interchange differs from Net Scheduled Interchange.o R2: PacifiCorp believes that this requirement is redundant to BAL-005-0.2b R12.1. o INT-010-2 R6: PacifiCorp believes the term “agreed upon values” should be amended to provide more clarity. PacifiCorp requests the SDT specify the method expected to be implemented in order to determine “agreed upon values” used by each BA to ensure limits are not exceeded. Specifically, PacifiCorp wonders if the agreed upon value is the value provided by the Reliability Adjustment Arranged Interchange or if the agreed upon value is based on a verbal communication.PacifiCorp supports the development of new draft Standard INT-011-1. This will support reliability of the BES because creation of the path using Point to Point Transmission Service indicates congestion is possible on that path and management of the path is needed to avoid leaning on other parallel paths.
Entergy Services, Inc.	Please consider utilizing existing functionality through the ownership factors in the IDC to document real time flows and impacts to Pseudo Ties. The concern is the compliance risk and administrative overhead to adjust these tags on an hourly basis.INT-004-3The Title of this standard has been modified from “Dynamic Interchange Transaction ModificationsÂ´ to “Dynamic Transfers”. Entergy recommends that it should be “Dynamic and Pseudo-Tie Interchange Transactions” to reflect inclusion of Dynamic Schedules and Pseudo-Ties.Effective Date: Since certain requirements, as written in this standard, are dependent on NAESB action to modify Electric Industry Registry, the effective date should reflect this dependency.R1 - “on time” included in this requirement is not defined in this standard. Timing requirements that were included in INT-005-3 are now included in INT-006-4. Entergy suggest that either “on-

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	time" referred to in this requirement specifically point to INT-006-4 Attachment 1 or this term be removed from this requirement. Similar reference in M-1 should be adjusted accordingly. There is no need to include the expected maximum MW profile. If the entity can come up with the maximum MW profile, it can also come up with the expected average MW profile. There is no benefit or reliability impact of knowing maximum MW profile. Entergy recommends not including the second bullet for maximum MW profile in the standard.R2 - The language in this requirement is odd. ...ensure the Confirmed Interchange...is reviewed and updated if needed for the next available..... This language is loose and it does not appear like a Standard requirement language. This is modification of the existing requirement that used a threshold of 10% or 25 MW for updating the profile. However, the new language by including the term "if needed" makes it vague. This requires comparing the actual integrated energy for an hour to be compared with the average energy profile for the next hour. The average energy profile for the next hour may actually be required to be more than 10% or more than 25 MW different from the previous hour. There is also not enough time for adjustment of the energy profile for the next hour as the actual integrated energy for an hour cannot be determined till after completion of that hour. Even though this requirement was already in INT-004-2, Entergy recommends to remove this requirement as it does not serve any reliability purpose, is just administrative burden, and difficult to implement.R-3 and R4 - These requirements are administrative and commercial in nature as these require to verify how losses will be accounted for and that sufficient (vague) information to reliably manage the Pseudo-Tie has been provided. These require verifying if these Pseudo-Ties are registered in the NAESB Electric Industry Registry, which capability does not even exist currently. These requirements do not have any reliability impact. Entergy recommends that these requirements should not be included in the reliability standards. Pseudo-Tie Tags will require adjustments almost every hour to stay in compliance, creating the need for costly software, increased staff to manage, and extremely large tag files which will choke systems and internal processes. The existing functionally in the IDC (if made a requirement) will provide greater visibility, accountability, and more accurate data - all contributing to increased reliability. The approval and coordination of Pseudo Ties prior to implementation is addressed in R3 & R4 and should be adequate to

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	provide the necessary visibility and awareness between all impacted Bas, TSP, and RCs.Please clarify Requirement 3.3.2. Each of the Balancing Authority's associated Reliability Coordinators (in the Eastern Interconnect) or associated Transmission Operators (in the Western Interconnection) has confirmed that sufficient information to reliably manage the Pseudo-Tie has been provided.INT-006-4The term "Reliability Adjustment Arranged Interchange" is not consistent with other NERC standards and the recommendation is to use "curtailment request".R1 - Reference to " so that these entities can conduct a reliability assessment of the Arranged Interchange before Arranged Interchange is implemented" is unnecessary in this requirement. Requirements for assessments are detailed in other requirements. Entergy recommends removing this reference/phrase.Attachment I, Column A specifies initial distribution of all Arranged Interchanges in less than or equal to one minute of its receipt. Description given in this requirement is very confusing. The phrase in second/last sentence "exceeding the times specified in Attachment 1, Column A..." tends to imply that the distribution can occur in more than one minute. The intent of this requirement needs to be clarified and language modified accordingly. R-2 - Foot note 2 is redundant. Since there is no requirement to provide response to any other requests, the foot note does not add any value. R3 - Foot note 3 is redundant. Since there is no requirement to provide response to any other requests, the foot note does not add any value. Though the note in Rationale for this requirement indicates that TSP may deny for other reasons, R3.1 limits the denial only if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid. Since Rationale is not part of the standard Entergy recommends including "other reasons" included in the requirement. TSP can deny if there are not enough scheduling rights (MW available on TSR).R6 - The language of the requirement is odd. Entergy suggests the language to be changed to: Each Sink Balancing Authority shall distribute all notifications of whether an Arranged Interchange was transitioned to Confirmed Interchange to the following entities such that on-time Confirmed Interchange can be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D:Interchange Authority - Since Interchange Authority is being replaced by the Sink Balancing Authority in these standards, definition of Interchange Authority is not needed any

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	more. SDT should recommend deletion of the definition of Interchange Authority from NERC Glossary.Attachment 1, Column C is not referenced in any Standard. It does not seem to have meaning? It was earlier referenced in INT-008-3 R1 that has been moved to INT-006-3 R6 and reworded. Entergy recommends reviewing this and modifying the language of R6, if needed.INT-009-2These following two terms (Attaining Balancing Authority and Native Balancing Authority) are different than other standards and customary terminology used in the industry. To avoid potential confusion or error it is recommended that "Source BA and Sink BA" be utilized.Attaining Balancing Authority: A Balancing Authority bringing generation or load into itseffective control boundaries through a dynamic transfer from the Native Balancing Authority.Native Balancing Authority: A Balancing Authority from which a portion of its physicallyinterconnected generation and/or load is transferred from its effective control boundaries to theAttaining Balancing Authority through a dynamic transfer.INT-010R1 - What is the reason of using the term "created" in place of originally used term "submitted" in existing standard? The Request for Interchange needs to be submitted and not only created, therefore Entergy recommends keeping the term "submitted".R2 - Same remark as R1 for the term "created".R3 - Same remark as R1 for the term "created".R5 - Use of the term "only to the Source Balancing Authority for reliability assessment tends to imply that if got distributed to any other entity, it is a violation. Entergy recommends removing the term "only" in this requirement. The term "Reliability Adjustment Arranged Interchange" is not consistent with other NERC standards and the recommendation is to use "curtailment request". The SDT is requested to clarify the term "energy sharing" used in R1: Each Sink Balancing Authority shall ensure that a Request for Interchange is created within 60 minutes of the start of the energy sharing, and with a start time no more than 60 minutes beyond the start of the energy sharing for Interchange scheduled in duration of more than 60 minutes as part of an energy sharing agreement The term "Reliability Adjustment Arranged Interchange" is used throughout the standard. We recommend changing and use "curtailment request".NAESB Business Practice Standards - There is a concern among the group on how the NERC Reliability Standards will remain in lock-step with the NAESB Business Practice Standards. Has there been an agreement reached on a process to use?INT-011This standard has been developed in response to the FERC

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	directive. This will also facilitate Parallel Flow Visualization (PFV) project that NAESB is working on. In case this standard does not get included in the final NERC standards, this will adversely impact the NAESB effort. Entergy supports this standard.
Brazos Electric Power Coop	Please make it clear that these standards will not apply in ERCOT.
MISO	Tagging of Pseudo-Ties (INT-004 and INT-009)We do not agree that Pseudo-Ties need to be tagged for the following reasons:1. The asset generator defines the reliability impact, and the allocation (tagging discussion) only deals with allocation of energy, which is a business practice. 2. When a unit is pseudo-tied, a new tie line is created between two entities. These new tie lines are subject to compliance with BAL-001, Requirement R1 and BAL-005-0.2, Requirements R12 - R13. These requirements already implement hourly checks of tie line data. This data provides inputs to the Net Actual Interchange, which are then utilized in the calculation of ACE, which is addressed in the Reliability Standards and requirements indicated above. This creates a potential redundancy of these obligations that could be eliminated.MISO respectfully suggests that the references to Pseudo-Ties should be removed from INT-004-3, Requirements R1-R4 and INT-009-2, Requirement R1. Requirement R2 of INT-009-2 should be removed in its entirety. If the Coordinate Interchange Standard Drafting Team moves forward with tagging Pseudo-Ties, we recommend that language be included that would allow an alternate method for reporting Pseudo-Ties, if they are included in a congestion management procedure such as market flows. Additionally, INT-004 R3.1 needs further clarification so only the BA with the in-kind scheduled loss is required to verify the loss.INT-006To operate reliably, an entity needs only a net interchange with its neighbor. The details of what customer transactions make up that net interchange is commercial/financial. These requirements represent the functions and actions necessary to effectively manage the details of interchange data. If this information were located in a NAESB Business Practice Standards and the NAESB Electronic Tagging Functional Specification, which are the source of the software specifications, and is open to the

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	industry for comment and voting, that would be adequate. MISO respectfully submits that all of INT-006 could be removed; however, at a minimum, R1 and R6 are the best candidates for removal.If the Coordinate Interchange Standard Drafting Team moves forward with INT-006, the MISO suggests the “shall deny” language in R2.1 be changed to “shall evaluate.” “Denying” is a right of the BA rather than an obligation when it comes to BA’s own capability. For example, if BA default ramp limit is 500 MW import, but in real time BA determines that it can handle one more schedule, it should have the right to approve that schedule.INT-009The purpose of INT-009-2 is to ensure that entities are operating to a common, but opposite Net Scheduled Interchange (“NSI”). The inputs to the NSI and Net Actual Interchange are then utilized in the calculation of ACE, which is addressed in BAL-005, Requirements R9-R12. Accordingly, the requirements set forth in INT-009-2 are essentially the inputs to the requirements contained in BAL-005, Requirements R9 - R12. The potential redundancy of these obligations could be eliminated if BAL-005 was modified for enhanced clarity including ensuring that inputs that are currently described in INT-009-2 are addressed in BAL-005-0.2. Such consolidation would provide benefits to reliability generally by ensuring that all obligations relative to the inputs into ACE are clearly described in one location and would eliminate the need for this Standard, which aligns with current efforts to ensure that there is not redundancy in the Reliability Standards. MISO respectfully suggests that the drafting team consider this redundancy as they finalize these standards.INT-010In implementation, Requirements R1 through R3 are essentially “administrative” as they ‘document’ the flow and associated actions after-the-fact. Because the operating time in which the actions and flow were necessary has already elapsed, it is important to note that Requirements R1 through R3 are not necessary for the reliability of the Bulk Electric System. Therefore, while it is good practice to document such activities, such documentation obligations are not appropriate for inclusion in the Reliability Standards. More specifically, the Reliability Standards should contain only requirements for activities that are necessary to maintain the reliability of the Bulk Electric System. After-the fact documentation activities do not meet this essential criterion for inclusion as requirements in the Reliability Standards. MISO respectfully suggests that such requirements be documented in best practices outside of the Reliability Standards. Further,

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	MISO respectfully requests that, if Requirement R1 is retained, the language is revised to ensure that the requirement more clearly states that its intended application is to After-The-Fact reliability adjustments.R4 is trying to ensure that the 'expedited' approval process reserved for reliability reasons is not utilized for non-reliability reasons. This documentation will only be reviewed "after-the-fact" and will not ensure that obligations and process are properly fulfilled and utilized in the normal course of business. Because the operating time in which the relief was requested has already elapsed, it is clear that Requirement R4 is not necessary to ensure the reliability of the Bulk Electric System. Therefore, while it is good practice to document the condition that prompted a request for relief, such documentation obligations are not appropriate for inclusion in the Reliability Standards because the Reliability Standards should contain only requirements for activities that are necessary to maintain the reliability of the Bulk Electric System. After-the fact documentation activities do not meet this essential criterion for inclusion as requirements in the Reliability Standards. MISO respectfully suggests that such requirements be documented in best practices outside of the Reliability Standards. MISO further notes that such documentation activities may distract entities by requiring the relation of real-time BES events to congestion management actions when such entities and their personnel should remain focused on relieving the system conditions. Finally, the requirement does not appear to leverage existing processes. For example, when a curtailment is requested through the IDC, many entities indicate the constrained element in the curtailment request. An alternative approach would be to require a reference to the initiating system condition at the time the relief is requested. More specifically, a reliability adjustment should not proceed through the curtailment process without the identification of the constrained element or condition in the adjustment request. MISO supports the expedited curtailment approval process set forth in Requirement R5. MISO respectfully suggests that Requirement R6 is unnecessary because it is a qualifier for the operation of a dynamic schedule that is already covered by an existing process, i.e., when someone gets a Tag curtailment, they have received notice to adjust the source generation. INT-011MISO requests clarification regarding how the INT-011 standard will be coordinated with changes to the IRO-006 Standards. Currently, IRO-006-EAST-1 R.3 has no provision for the Reliability Coordinator

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	issuing a TLR to instruct the receiving Reliability Coordinator to curtail intra-Balancing Authority Area Point to Point Transmission Service, and IRO-006-EAST-1 R.4 has no provision for the receiving Reliability Coordinator to instruct the Balancing Authority to implement intra-Balancing Authority Point to Point Transmission Service schedule change requests.
MRO NERC Standards Review Forum (NSRF)	The NSRF wishes to thank the CISDT and recommend the following recommendations:Tagging of Pseudo-Ties (INT-004 and INT-009)We do not agree that Pseudo-Ties need to be tagged, because the asset generator defines the reliability impact, and the allocation (tagging discussion) only deals with allocation of energy which is a business practice. The references to Pseudo-Ties should be removed from INT-004 R1-R4 and INT-009 R1-R2. INT-006At a minimum, R1 and R6 are the best candidates for removal, though all of INT-006 could be removed.To operate reliably, an entity needs only a net interchange with its neighbor. The details of what customer transactions make up that net interchange is commercial/financial. These requirements represent the functions and actions necessary to effectively manage the details of interchange data. If this information were located in a NAESB Business Practice Standards and the NAESB Electronic Tagging Functional Specification, which are the source of the software specifications, and is open to the industry for comment and voting, that would be adequate. INT-009BAL-005 R9-R12 could be modified to be clearer and incorporate the language/intent of these requirements. Thus, this Standard would no longer be necessary. When specifically reviewing R3, although this requirement has been present since the original policy language was converted to standards; it is an obvious function that is required in order for the flow to be set as desired. This is comparable to generators needing to be told where to operate but there is no requirement for ‘who’ to notify them. INT-010R1-R3 are administrative to ‘document’ the flow after-the-fact. Real Time has already passed so it is not necessary for reliability. It is good practice to do these activities but they should be documented in best practices outside of the requirements.R4 is simply trying to enforce that entities don’t use the ‘expedited’ approval process for non-reliability reasons. A description in NAESB business practices would be adequate. R5 may have some reliability value in that we desire an expedited

Organization	Question 1 Comment
	process to have a curtailment approved.
ISO New England Inc.	We agree with the Independent Expert Panel's recommendation that a number of the Reliability Standards are being addressed through the functional specifications. INT-004ISO-NE does not currently have interchange associated with dynamic transfers. However, where dynamic transfers are utilized we believe that the transparency these requirements provide is necessary for reliability.INT-006Based on the ISO-NE market design, ISO-NE needs only a net interchange with our neighbor to operate reliably. The details of what customer transactions make up that net interchange is purely commercial/financial under our market design. ISO-NE also does not have loop flow issues with our neighbors and the individual transaction information is not required to manage congestion on our system. If these INT-006 requirements were not contained in NERC standards and interchange transactions are not acted upon in the timeframes defined in these requirements, the ISO-NE markets would continue to economically dispatch generation with respect to any interchange that is available. If no interchange were available the ISO-NE markets have mechanisms in place to ensure that load is served. As such, ISO-NE agrees with the Expert Panel's observation that guidelines exist in the functional specification for electronic tagging. However, the details in that specification were developed based on the language in these standards. If these requirements are removed from the NERC standards, they must reside somewhere in business language that can be voted on by the industry that would continue to drive changes to the eTag specification. If this information were located in a NAESB Business Practice Standards, which are the source of the software specifications, and are open to the industry for comment and voting, that approach would be adequate to serve the reliability needs of ISO-NE. INT-009ISO-NE believes that BAL-005 R9-R12 could be modified to be clearer and incorporate the language/intent of R1 and R2 of INT-009. INT-009 R3has been present in some form since the original policy language was converted to standards. While it is an obvious function that is required in order for the flow to be set as desired, this is comparable to generators needing to be told where to operate but there is no NERC requirement for 'WHO' to notify them. We believe this requirement can be

Organization	Question 1 Comment
	removed.INT-010R1-R3 are administrative tasks to document the flow directed by an RC after-the-fact. Since they are after-the-fact actions, they are clearly not necessary for reliability. While we agree is necessary for transparency we believe it would be adequate to locate this requirement in a NAESB Business Practice Standard. R4 is trying to enforce that entities do not use the 'expedited' approval process for non-reliability reasons. ISO-NE believes a description in NAESB business practices would be adequate. R5 can impact reliability; an expedited process is needed to ensure curtailments occur in a timely manner.. However, since an RC can direct an entity to take action without an approved eTag, it may be adequate to have the NAESB Business Practice Standards define who those approval entities must be to support the software design that would occur for typical interchange processing. The description in the Background section for R6 does not quite align with the requirement language. We believe that R6 could be unnecessary if the language in BAL-005 R9-R12 are updated to use results based standard language. This proposed requirement seems to more of an instruction of HOW someone with a Dynamic Schedule should follow a reliability adjust; and may be more appropriate in the Guidelines and Technical Basis section of INT-004. Another observation/question, is the language in INT-004 R2.3 intended to have the same outcome? There are other NERC Standards that require operating entities to follow directions of their RC, TOP and BA, so this is already covered elsewhere.
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation and Energy Marketing	We agree with the SDT's disposition of the Paragraph 81 recommendations in the current draft of the INT standards posted. Southern Company would like to take this opportunity to point out that there will be additional burdens and administrative tasks from a compliance perspective due to changes introduced in the current INT proposed standards, namely the requirement to E-tag Pseudo-Tie transactions. Southern believes that the current implementation of the IDC allows for adequate representation of Pseudo-tie transactions for consideration in reliability curtailments. It appears to us that the requirement to E-tag Pseudo-Tie transactions will result in increased regulatory exposure for entities with little net benefit to

Organization	Question 1 Comment
	the overall reliability of the bulk electric system.
Independent Electricity System Operator	We do not believe that any specific requirements in the proposed INT-004-3, INT-006-4, INT-009-2, INT-010-2, or INT-011-1 could be better addressed through alternate means than a NERC Reliability Standard.We generally agree with the recommendations that a number of the INT standard requirements can be addressed through the functional specifications of E-tag, especially those that address information exchange at the Arranged Interchange stage. Still, the requirements for the e-tag submission process need to be retained somewhere. If this process is to be moved over to NAESB's business practices, then it is important that coordination with NAESB be initiated as soon as possible to ensure its business practices are ready for implementation when the revised INT standards become effective.
SERC OC Review Group	We recommend that the SDT consider utilizing existing functionality through the ownership factor in the IDC to document real time flows and impacts of Pseudo Ties. The concern is the compliance risk and administrative overhead to adjust these tags on an hourly basis.INT-004-3The SDT is requested to clarify Requirement 3.3.2. Each of the Balancing Authority's associated Reliability Coordinators (in the Eastern Interconnection) or associated Transmission Operators (in the Western Interconnection) has confirmed that sufficient information to reliably manage the Pseudo-Tie has been provided. Modify statement: Pseudo Tie Tags will require adjustments almost every hour to stay in compliance, creating the need for costly software, increased staff to manage, and extremely large tag files which will choke systems and internal processes. The existing functionally in the IDC, (add: when used, and current reporting of market flows,)(delete: if made a requirement) will provide greater visibility, accountability, and more accurate data-all contributing to increased reliability.The approval and coordination of Pseudo Ties prior to implementation is addressed in R 3 & 4 and should be adequate to provide the necessary visibility and awareness between all impacted BAs, TSPs, and RCs.INT-006-4We recommend that R4 be reworded based on current NERC Glossary. The Glossary

Organization	Question 1 Comment
	currently defines “Reliability Adjustment”, “Arranged Interchange”, and “Curtailment”. We would suggest that the new language read: R4. Each Balancing Authority receiving a Reliability Adjustment (insert: to) Arranged Interchange shall approve or deny it prior to the expiration of the reliability assessment period defined in the timing requirements in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 4.1. If a Balancing Authority denies a Reliability Adjustment (insert: to) Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than10 minutes after the denial.Further, we recommend deleting the “Reliability Adjustment Arranged Interchange from the proposed standard.INT-009-2These following two terms (Attaining Balancing Authority and Native Balancing Authority) are different than other standards and customary terminology used in the industry. To avoid potential confusion or error it is recommended that “Source BA and Sink BA” be utilized.Attaining Balancing Authority: A Balancing Authority bringing generation or load into itseffective control boundaries through a dynamic transfer from the Native Balancing Authority.Native Balancing Authority: A Balancing Authority from which a portion of its physicallyinterconnected generation and/or load is transferred from its effective control boundaries to theAttaining Balancing Authority through a dynamic transfer.INT-010-2 We recommend that the term Reliability Adjustment Arranged Interchange be reworded based on current NERC Glossary. The Glossary currently defines “Reliability Adjustment”, “Arranged Interchange”, and “Curtailment”. We would suggest that the new language read: R4. Each Reliability Coordinator, Balancing Authority or Transmission Service Provider that initiates a Reliability Adjustment (insert: to) Arranged Interchange must have experienced one or more of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same Day Operations, Real Time Operations]M4. Each applicable entity shall have evidence such as dated and time-stamped logs, voice recordings, electronic records, or other similar evidence that when it created a Reliability Adjustment (insert: to) Arranged InterchangeR5. Each Sink Balancing Authority shall distribute any Reliability Adjustment (insert: to) Arranged Interchange only to the Source Balancing Authority for reliability assessment. [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations]M5. The Sink Balancing Authority shall have

Organization	Question 1 Comment
	evidence such as dated and time stamped electronic logs or other similar evidence that it distributed any Reliability Adjustment (insert: to) Arranged Interchange only to the Source Balancing Authority for reliability assessment. (R5)R6. Each Balancing Authority involved in a Reliability Adjustment (insert:to)Arranged Interchange involving a Dynamic Schedule shall use agreed upon values that ensure any limit established by the Reliability Adjustment Arranged Interchange is not exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations]M6. The Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that following any Reliability Adjustment (insert: to) Arranged Interchange involving a Dynamic Schedule it used agreed upon values that ensured any limit established by the Reliability Adjustment Arranged Interchange was not exceeded. (R6)Further, we recommend deleting the "Reliability Adjustment Arranged Interchange from the proposed standard.The SDT is request to clarify the term "energy sharing" used in R1: Each Sink Balancing Authority shall ensure that a Request for Interchange is created within 60 minutes of the start of the energy sharing, and with a start time no more than 60 minutes beyond the start of the energy sharing for Interchange scheduled in duration of more than 60 minutes as part of an energy sharing agreement NAESB Business Practice Standards - There is a concern among the group on how the NERC Reliability Standards will remain in lock-step with the NAESB Business Practice Standards. Has there been an agreement reached on a process to use?The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
SPP Standards Review Group	We take note of the inclusion of a tagging requirement for Pseudo-Ties that currently does not exist and wonder what has led the drafting team to reach this conclusion. We also wonder if this change will result in significant reliability improvements worthy of the extra effort needed to implement the change. That being the case, we could support the exclusion of Pseudo-Ties from the tagging requirements in INT-004-3 and INT-009-2.INT-004-3We have concern with including requirements (R4) that are dependent upon the existence of a registry in NAESB that

Organization	Question 1 Comment
	currently doesn't exist. How will we be notified when the registry is implemented and how can we be assured that we will be given adequate time to make the proper submittals? We wonder why R4 was even included in the draft INT-004-3 given this situation.There was no explanation given as to what the drivers were for making the definition changes to several key terms. Could the drafting team please provide some reasoning here, especially regarding the replacement of Interchange Transaction Tag with Request for Interchange?Replace 'real time' with 'Real-time' in the definitions of Dynamic Schedule and Pseudo-Tie. The latter is in the NERC Glossary of Terms. Make the same change in Requirement 3.1.In Section 5. Background, delete the 'that' at the end of the 4th line in the first bullet.Insert 'when' in M4 such that it reads: The Balancing Authority shall have evidence (...) that it only approved a Pseudo-Tie Arranged Interchange when the Pseudo-Tie is registered in the NAESB Electric Industry Registry.Reword the Severe VSL for R3 such that it reads: The Balancing Authority approved a Pseudo-Tie Arranged Interchange for a Pseudo-Tie and neither Part 3.1 nor Part 3.2 were met.In the Guidelines and Technical Basis Section in the Application Guidelines, be sure that Dynamic Schedule and Pseudo-Tie are capitalized properly.In the table in the Application Guidelines, capitalize Frequency Bias. It is a NERC defined term. Also, shouldn't consideration be given to manual load shedding outside of an EEA event which is included in the table?INT-006-4Adjacent Balancing Authority is listed in the Definition of Terms Section but it is the same definition as that in the NERC Glossary of Terms. Why is it listed? Shouldn't it be removed?Replace the 'or' with an 'and' in the 4th line of M4.INT-009-2Insert 'and Pseudo-Ties' following Dynamic Schedules in the 3rd line of M1. Also make this same insertion in the Severe VSL for R1.Replace the 'the' in front of HVDC tie with an 'an' in the 1st line of R3 and the last line of M3. Also make this same change in the Severe VSL for R3.INT-010-2Capitalize real-time in Requirement 4.5 and in M4.

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
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7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

Description of Current Draft

This is the third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	September - October 2013
Recirculation ballot	December 2013
BOT adoption	January 2014
File standard with regulatory authorities.	February 2014

Effective Dates

First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed revisions to existing definitions (redlined to show changes):

Dynamic Interchange Schedule or Dynamic Schedule: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in real time and ~~used~~ included in the Net Interchange Scheduled term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes). ~~as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.~~

Pseudo-tie: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in real time and included in the Net Interchange Actual term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).~~used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.~~

Standards impacted by the above revisions: BAL-002-WECC-2, BAL-003-0.1b and BAL-005-0.2b

Request for Interchange (RFI) - A collection of data as defined in the NAESB Business Practice Standards ~~RFI Datasheet,~~ to be submitted to the ~~Interchange~~ Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.

Arranged Interchange - The state where the ~~Interchange~~ Sink Balancing Authority has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).

Confirmed Interchange - The state where no party has denied and all required parties have approved ~~the Interchange Authority has verified~~ the Arranged Interchange.

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule. ~~(This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)~~

Intermediate Balancing Authority - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority. ~~Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.~~

Proposed new definitions:

Attaining Balancing Authority: A Balancing Authority bringing generation or load into its effective control boundaries through a dynamic transfer from the Native Balancing Authority.

Native Balancing Authority: A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a dynamic transfer.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Dynamic Transfers**
2. **Number:** INT-004-3
3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.
4. **Applicability:**

   4.1. Balancing Authority

   4.2. Load-Serving Entity
5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of dynamic transfers.

   - R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement replaces the Purchasing Selling Entity with the Load Serving Entity and Pseudo-Ties were added.
   - R2 is modified from INT-004-2 to separate the triggers for the review of the dynamic transfer and when a modification is required for the dynamic transfer.
   - R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo Ties ensure that all entities involved are aware of the dynamic transfer and agree that that the various responsibilities associated with the dynamic transfer have been agreed upon.
   - R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
   - The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any dynamic transfer.

B. Requirements and Measures

R1. Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]

Rationale for R1: This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI.

M1. The Load-Serving Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties on-time. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the Load-Serving Entity shall have evidence such as IDC model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)

R2. Each Load-Serving Entity that submits a Request For Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.

2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.

2.3. The Load-Serving Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

M2. The Load-Serving Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation met the criteria in Requirement R2, Parts 2.1- 2.3. (R2)

R3. Each Attaining Balancing Authority shall register each Pseudo-Tie for which data is used in its ACE equation in the NAESB Electric Industry Registry in order to support congestion management procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it registered a Pseudo-Tie in the NAESB Electric Industry Registry prior to its implementation. (R3)

Rationale for R3: This Requirement is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. Transparency of all Pseudo-Ties ensures proper modeling by all impacted entities. This requirement will become effective when the NAESB EIR accepts Pseudo-Tie registrations. Requirements for Pseudo-Tie registration will be defined in NAESB business practices which are developed through open industry practices. All existing Pseudo-Ties will need to be registered and verified. This will be addressed in the Project 2008-12 implementation plan.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Load-Serving Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Load-Serving Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a Load-Serving Entity or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The Load-Serving Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method,
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.
R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority did not register a Pseudo-Tie for which data was

						used in its ACE equation in the NAESB Electric Industry Registry.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-ties are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as scheduled interchange. The obligations of the entities involved in each type of dynamic transfer are dependent on the type of dynamic transfer selected. These guidelines provide items that should be considered when determining which type of dynamic transfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a dynamic transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
    - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services FERC OATT Schedules 3–6 and other ancillary services as	Attaining BA	Native BA

required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE frequency bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BA(s) by the pseudo-tie	The Attaining BA should include the load from its dynamic schedule as a part of its forecast load to set frequency bias requirement. The Native BA should change its load used to set frequency bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

In NERC's Dynamic Transfer Reference Guidelines, Version 2, it describes unique handling of curtailments of dynamic transfers.

For Dynamic Schedules:

> **If transmission service between the source and sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including dynamic schedules, may have to be curtailed accordingly. All BAs involved in a dynamic schedule curtailment must also adjust the dynamic schedule signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed dynamic schedule tag. Since dynamic schedule tags are generally not used as dynamic transfer signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-ties:

> **If transmission service between the native and attaining BA(s) is curtailed, then the allowable range of the magnitude of the pseudo-ties between them must be limited accordingly to these constraints.**

Both sections above describe that when curtailments (typically communicated through e-Tags) of dynamic transfers occur, they require additional action by Balancing Authorities to ensure compliance with the curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including curtailments, in Dynamic Schedule and Pseudo-tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

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This is the ~~second~~third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

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45-day Formal Comment Period with Parallel Initial Ballot	~~July~~September - October 2013
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BOT adoption	~~November 2013~~January 2014
File standard with regulatory authorities.	~~December 2013~~February 2014

Effective Dates

First day of the second calendar quarter ~~beyond~~after the date that this standard is approved by an applicable ~~regulatory authorities, or~~governmental authority or as otherwise provided for in ~~those jurisdictions~~a jurisdiction where ~~regulatory~~ approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard ~~becomes~~shall become effective on the first day of the ~~second~~first calendar quarter ~~beyond~~that is six months after the date this standard is ~~approved~~adopted by the NERC Board of Trustees~~,~~ or as otherwise ~~made effective pursuant to the laws applicable to such ERO governmental authorities~~provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. ~~New or revised definitions listed below become approved when the proposed standard is approved.~~ When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed revisions to existing definitions (redlined to show changes):

Dynamic Interchange Schedule or Dynamic Schedule: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in real time and ~~used~~ included in the Net Interchange Scheduled term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes). ~~as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.~~

Pseudo-~~Tie~~tie: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in real time and included in the Net Interchange Actual term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).~~used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.~~

Standards impacted by the above revisions: BAL-002-WECC-2, BAL-003-0.1b and BAL-005-0.2b

Request for Interchange (RFI) - A collection of data as defined in the NAESB Business Practice Standards ~~RFI Datasheet,~~ to be submitted to the ~~Interchange~~ Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.

Arranged Interchange - The state where the ~~Interchange~~ Sink Balancing Authority has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).

Confirmed Interchange - The state where ~~the Sink Balancing~~no party has denied and all required parties have approved ~~the Interchange Authority has verified~~ the Arranged Interchange.

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule. ~~(This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)~~

Intermediate Balancing Authority - A Balancing Authority ~~involved in~~on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority. ~~Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.~~

Proposed new definitions:

Attaining Balancing Authority: A Balancing Authority bringing generation or load into its effective control boundaries through a dynamic transfer from the Native Balancing Authority.

Native Balancing Authority: A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a dynamic transfer.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Dynamic Transfers**
2. **Number:** INT-004-3
3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Load-Serving Entity
5. **Background:**

This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of dynamic transfers.

- R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement replaces the Purchasing Selling Entity with the Load Serving Entity and Pseudo-Ties were added.
- R2 ~~are~~is modified from INT-004-2 to ~~incorporate~~separate the triggers for the review of the dynamic transfer and when a modification is required for the dynamic transfer.
- R1 and R2 now also apply to Pseudo-Ties. The requirements to ~~submit a RFI for each Pseudo-Tie that are comparable to the existing requirements for Dynamic Schedules. The requirements in this standard to~~ create an RFI for Pseudo Ties ensure that all entities involved are aware of the dynamic transfer and agree that that the various responsibilities associated with the dynamic transfer have been agreed upon.
- ~~R2~~R3 is ~~modified to separate the triggers for the review of the dynamic transfer and when a modification is required for the dynamic transfer.~~
- ~~R3 and R4 are~~ created to ~~address the~~ensure that coordination ~~that must occur~~occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
- ~~The responsibilities that must be determined when establishing a Pseudo-Tie extend to such items as Disturbance Control Standard (DCS) recovery, load shedding, transmission and ancillary services, and load forecasting.~~ The Guidelines and Technical Basis section ~~of this standard summarizes~~was added to provide a summary of the considerations that must be given when establishing any dynamic transfer.

B. Requirements and Measures

Rationale for R1: This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI.

R1. Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie~~ at either:~~, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]

- ~~The expected average MW profile for each hour if a forecast for the Dynamic Schedule or Pseudo-Tie is available, or~~
- ~~The expected maximum MW profile for each hour if no forecast for the Dynamic Schedule or Pseudo-Tie is available.~~

M1. The Load-Serving Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that ~~RFIs were~~a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties on-time~~ and either at~~. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the ~~expected average profile~~Load-Serving Entity shall have evidence such as IDC model data or written / electronic agreement with a Balancing Authority to include the ~~expected maximum profile for each hour.~~Pseudo-Tie in the congestion management procedure(s). (R1)

R2. Each Load-Serving Entity that ~~secures energy to serve Load via~~submits a ~~Dynamic Schedule or Pseudo-Tie~~Request For Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is ~~reviewed and~~ updated~~ if needed~~ for ~~the next available scheduling hour and~~ future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

2.1. For Confirmed Interchange ~~using the expected average MW profile, if the average energy profile in an hour is~~ greater than 250 MW ~~and in that~~for the last hour, the actual hourly integrated energy deviates from the ~~hourly average energy profile for the next hour indicated in the~~ Confirmed Interchange by more than 10~~%.~~% for that hour and that deviation is expected to persist.

~~**2.1.1.** The Load-Serving Entity shall ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours if the review performed in R2 indicates that a deviation of more than 10% will persist.~~

2.2. For Confirmed Interchange ~~using the expected average MW profile, if the average energy profile in an hour is~~ less than or equal to 250 MW ~~and in that~~for the last hour, the actual hourly integrated energy deviates from the ~~hourly average energy profile indicated in the~~ Confirmed Interchange by more than 25 MW for that hour and ~~this~~that deviation is expected to ~~continue in future hours~~persist.

~~**2.2.1.** The Load-Serving Entity shall ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours if the review performed in R2 indicates that a deviation of more than 25 MW will persist.~~

2.3. ~~Receipt of~~ The Load-Serving Entity receives notification from a Reliability Coordinator or Transmission Operator ~~that a deviation from the hourly energy profile indicated in the Confirmed Interchange, regardless of magnitude, is a reliability concern and requires that the Confirmed Interchange be updated.~~to update the Confirmed Interchange.

M2. The Load-Serving Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it ~~reviewed and~~ updated ~~as needed~~ its ~~RFIs~~Confirmed Interchange Requests for Interchange when the deviation met ~~or exceeded~~ the criteria in Requirement R2, Parts 2.1-2.3. (R2)

~~Rationale for R3: This Requirement is intended to ensure that a Pseudo-Tie is properly established. This requirement will be effective until the NAESB registry accepts Pseudo-Tie registrations.~~

Rationale for R3: T
intended to ensure
properly establishe
implementation. T
Ties ensures prope
entities. This requirement will become effective when the NAESB EIR accepts Pseudo-Tie registrations. Requirements for Pseudo-Tie registration will be defined in NAESB business practices which are developed through open industry practices. All existing Pseudo-Ties will need to be registered and verified. This will be addressed in the Project 2008-12 implementation plan.

R3. Each Attaining Balancing Authority shall ~~verify that~~register each ~~of the following conditions has been met prior to approving a~~ Pseudo-Tie ~~Arranged Interchange~~ for which data is used in its ACE equation in the NAESB Electric Industry Registry in order to support congestion management ~~capabilities~~ [1]procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*~~]:~~]

~~**3.1.** Any Intermediate Balancing Authority that schedules in-kind losses in real-time related to the Pseudo-Tie has identified how losses will be accounted for over their Balancing Authority Area.~~

~~**3.2.** Each of the Balancing Authority's associated Reliability Coordinators (in the Eastern Interconnection) or associated Transmission Operators (in the Western Interconnection) has confirmed that sufficient information to reliably manage the Pseudo-Tie has been provided.~~

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[1] ~~The ERCOT and Hydro Quebec Interconnections have not been included in this requirement, as they are single Balancing Authority Interconnections and only connected to other Balancing Authorities through HVDC tie-lines.~~

~~**M3.** The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it approved a Pseudo-Tie Arranged Interchange subject to Requirement R3, Parts 3.1-3.2. (R3)~~

~~**R4.** Each Balancing Authority shall verify the Pseudo-Tie is registered in the NAESB Electric Industry Registry prior to approving a Pseudo-Tie Arranged Interchange in order to support congestion Management. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]~~

~~Rationale for R4: This Requirement is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. This requirement will become effective when the NAESB registry accepts Pseudo-Tie registrations. Until such time, R3 will be in effect.~~

~~**M4.**~~**M3.** The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it ~~only approved~~ registered a Pseudo-Tie ~~Arranged Interchange the Pseudo-Tie is registered~~ in the NAESB Electric Industry Registry~~. (R4~~ prior to its implementation. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Load-Serving Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Load-Serving Entity shall maintain evidence to show compliance with R1~~,~~ and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 ~~and R4~~ for the most recent 3 calendar months plus the current month.

If a Load-Serving Entity or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit~~s~~

Self-Certification~~s~~

Spot Check~~ing~~

Compliance ~~Violation Investigations~~Investigation

Self-Reporting

~~Complaints Text~~

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The Load-Serving Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie ~~and had a forecast for that Dynamic Schedule or Pseudo-Tie, but~~, did not ensure that ~~an RFI with the expected average MW profile for each hour~~ a Request for Interchange was submitted as ~~an~~ on-time Arranged Interchange to the Sink Balancing Authority~~.~~ ~~OR~~ ~~The Load-Serving Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie,~~ and did not ~~have a forecast for that Dynamic Schedule or Pseudo-Tie, but did not ensure that an RFI with the expected maximum MW profile for each hour was submitted as an on-time Arranged~~

						~~Interchange to the Sink Balancing Authority.~~include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method,
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for ~~the next available scheduling hour or failed to ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.~~ future hours.
~~R3~~	~~Operations Planning~~	~~Lower~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority approved a Pseudo-Tie Arranged Interchange for a Pseudo-Tie and any of Parts 3.1, 3.2 were not met.~~

~~R4~~R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority ~~approved~~did not register a Pseudo-Tie ~~Arranged Interchange~~ for ~~a Pseudo-Tie that is not registered~~which data was used in its ACE equation in the NAESB Electric Industry Registry.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-ties are accounted for by all parties as actual ~~i~~Interchange and ~~dynamic schedules~~Dynamic Schedules are accounted for as scheduled interchange. The obligations of the entities involved in each type of dynamic transfer are dependent on the type of dynamic transfer selected. These guidelines provide items that should be considered when determining which type of dynamic transfer should be utilized for a given situation.

General Considerations ~~when establishing and implementing dynamic transfers~~When Establishing and Implementing Dynamic Transfers:

- During the setup of a dynamic transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
    - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the ~~Table 1~~table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services FERC OATT Schedules 3–6	Attaining BA	Native BA

and other ancillary services as required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE frequency bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BA(s) by the pseudo-tie	The Attaining BA should include the load from its dynamic schedule as a part of its forecast load to set frequency bias requirement. The Native BA should change its load used to set frequency bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

In NERC's Dynamic Transfer Reference Guidelines, Version 2, it describes unique handling of curtailments of dynamic transfers.

For Dynamic Schedules:

> **If transmission service between the source and sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including dynamic schedules, may have to be curtailed accordingly. All BAs involved in a dynamic schedule curtailment must also adjust the dynamic schedule signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed dynamic schedule tag. Since dynamic schedule tags are generally not used as dynamic transfer signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-ties:

> **If transmission service between the native and attaining BA(s) is curtailed, then the allowable range of the magnitude of the pseudo-ties between them must be limited accordingly to these constraints.**

Both sections above describe that when curtailments (typically communicated through e-Tags) of dynamic transfers occur, they require additional action by Balancing Authorities to ensure compliance with the curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including curtailments, in Dynamic Schedule and Pseudo-tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

Description of Current Draft

This is the third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	September – October 2013
Recirculation ballot	December 2013
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1.0	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2.0	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3.0	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3.0	July 1, 2010	Approved by FERC	Revised
4.0	TBD	Adopted by the NERC Board Of Trustees	Revised in Project 2008-12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed Revised Definitions (redlined to show proposed changes):

Arranged Interchange - The state where the ~~Interchange~~ Sink Balancing Authority has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).

Confirmed Interchange - The state where no party has denied and all required parties have approved ~~the Interchange Authority has verified~~ the Arranged Interchange.

Adjacent Balancing Authority - A Balancing Authority Area whose Balancing Authority Area ~~that~~ is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

Intermediate Balancing Authority - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority. ~~Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.~~

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule. ~~(This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)~~

Source Balancing Authority - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for the resulting Interchange Schedule. ~~(This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)~~

Proposed New Definition:

Reliability Adjustment Arranged Interchange - Request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Evaluation of Interchange Transactions**
2. **Number:** INT-006-4
3. **Purpose:** To ensure that entities conduct a reliability assessment of each Arranged Interchange before it is implemented.
4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Service Provider

5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-006-4 continues to be the reliability assessment of Interchange Transactions prior to their implementation.

   The content of INT-006-4 has been revised and expanded in the following manner:

   - R1 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Balancing Authority must deny the transition.
   - R2 was created by revising R1 from INT-006-3. This requirement ensures that Transmission Service Providers involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Transmission Service Provider must deny the transition.
   - R3 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange.
   - R4 was created by moving and revising R1 from INT-007-1, which has been retired as part of the project. This requirement lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange.
   - R5 was created by moving and revising R1 from INT-008-3, which has been retired as part of the project. This requirement lists the entities to which a Sink Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.
   - Attachment 1 timing tables for WECC were modified to address scheduling on a 15 minute basis.

Requirements and Measures

Rationale for R1: Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the scheduling path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

M1. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R1)

Rationale for R2: TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in Requirement R1, Part 2.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

R2. Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M2. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R2)

R3. The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

3.1. If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.

M3. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request or that it communicated denial to the Reliability Coordinator no more than 10 minutes after the denial. (R3)

R4. Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

- It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

M4. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that, under the conditions in R4, it did not transition an Arranged Interchange to Confirmed Interchange. (R4)

R5. For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

5.1. The Source Balancing Authority,

5.2. Each Intermediate Balancing Authority,

5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,

5.4. Each Transmission Service Provider included in the Arranged Interchange, and

5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

M5. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it notified the entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D. (R5)

B. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, R4, and R5 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R3 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny its transition to Confirmed Interchange prior to the expiration of the time period defined in Attachment 1, Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange. OR The scheduling path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange.
R2	Operations Planning, Same-day	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time Arranged Interchange or an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operations, Real-time Operations					emergency Arranged Interchange did not approve or deny its transition to Confirmed Interchange prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
R3	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
R4	Operations Planning, Same-day	Lower	N/A	N/A	N/A	The Sink Balancing Authority failed to confirm that none of the conditions in Requirement

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operations, Real-time Operations					4 existed before transitioning an Arranged Interchange to Confirmed Interchange.
R5	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Sink Balancing Authority did not notify all of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.	The Sink Balancing Authority did not notify the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange. OR The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify the entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Attachment 1 – Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [1] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[2]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[5]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time		≤ 20 minutes from Arranged Interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start

[1] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[2] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

[redacted] Attachment 1 – Timing Tables

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[7]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<10 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is not the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 5 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 6 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start

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[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[4] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[7]**	**BA Prepares Confirmed Interchange for Implementation**
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 7 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 8 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 9 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time		By 12:00 PPT of day the Arranged Interchange was received		≥ 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - All reliability entities involved in the Arranged Interchange are valid.
    - Generation source and load sink are defined.
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
    - Distribute notification as each entity approves or denies an Arranged Interchange.
    - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
    - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

  - Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
  - Receive distribution of Arranged Interchange
  - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
  - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
  - Submit a request to modify Interchange

- While interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
  - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
  - How to notify others that it is activating the plan
  - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
  - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
  - Delegation of approval rights and proxy actions, if such approaches will be used.
  - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
  - Personnel plans for short-term and extended periods.
  - Training of personnel in the use of the plan.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

Description of Current Draft

This is the ~~second~~third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	~~July~~September – October 2013
Recirculation ballot	~~October~~December 2013
BOT adoption	~~November 2013~~February 2014
File standard with regulatory authorities.	~~December 2013~~February 2014

Effective Dates

First day of the second calendar quarter ~~beyond~~after the date that this standard is approved by an applicable ~~regulatory authorities, or~~governmental authority or as otherwise provided for in ~~those jurisdictions~~a jurisdiction where ~~regulatory~~ approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard ~~becomes~~shall become effective on the first day of the ~~second~~first calendar quarter ~~beyond~~that is six months after the date this standard is ~~approved~~adopted by the NERC Board of Trustees~~,~~ or as otherwise ~~made effective pursuant to the laws applicable to such ERO governmental authorities~~provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1.0	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2.0	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3.0	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3.0	July 1, 2010	Approved by FERC	Revised
4.0	TBD	Adopted by the NERC Board Of Trustees	Revised in Project 2008-12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. ~~*New or revised definitions listed below become approved when the proposed standard is approved.*~~ *When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

Proposed Revised Definitions~~*:*~~ *(redlined to show proposed changes):*

Arranged Interchange - The state where the ~~Interchange~~ Sink Balancing Authority has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).

Confirmed Interchange - The state where no party has denied and all required parties have approved ~~the Sink BalancingInterchange Authority has verified~~ the Arranged Interchange.

Adjacent Balancing Authority - A Balancing Authority Area whose Balancing Authority Area ~~that~~ is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

Intermediate Balancing Authority - A Balancing Authority ~~involved in~~on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority. ~~Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.~~

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule. ~~(This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)~~

Source Balancing Authority - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for the resulting Interchange Schedule. ~~(This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)~~

Proposed New Definition:

Reliability Adjustment Arranged Interchange - Request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Evaluation of Interchange Transactions**
2. **Number:** INT-006-4
3. **Purpose:** To ensure that entities conduct a reliability assessment of each Arranged Interchange before it is implemented.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Transmission Service Provider
5. **Background:**

This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-006-4 continues to be the reliability assessment of Interchange Transactions prior to their implementation.

The content of INT-006-4 has been revised and expanded in the following manner:

- ~~R1 was created by moving and revising R1 from INT-005-3, which has been retired as part of the project. This requirement ensures that Arranged Interchange is properly distributed to the relevant parties for reliability assessment.~~
- ~~R2~~R1 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Balancing Authority must deny the transition.
- ~~R3~~R2 was created by revising R1 from INT-006-3. This requirement ensures that Transmission Service Providers involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Transmission Service Provider must deny the transition.
- ~~R4~~R3 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange.
- ~~R5~~R4 was created by moving and revising R1 from INT-007-1, which has been retired as part of the project. This requirement lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange.
- ~~R6~~R5 was created by moving and revising R1 from INT-008-3, which has been retired as part of the project. This requirement lists the entities to which a Sink

Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.

- Attachment 1 timing tables for WECC were modified to address scheduling on a 15 minute basis.

Requirements and Measures

~~R1.~~ Each ~~Sink~~ Balancing Authority shall ~~distribute~~ approve or deny each ~~Arranged Interchange to the Source Balancing Authority, each Intermediate Balancing Authority, and each Transmission Service Provider included in the Arranged Interchange so that these entities can conduct a reliability assessment of the Arranged Interchange before the Arranged Interchange is implemented. When distributing Arranged Interchange, each Sink Balancing Authority shall ensure that each distribution exceeding the times specified in Attachment 1, Column A, does not result in either of the following: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Same-day Operations, Real-time Operations*]~~

Rationale for R1: Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

~~1.1. On-time[1] Arranged Interchange where not all Balancing Authorities and Transmission Service Providers either approved or denied as specified in R2, R3, and R4.~~

~~1.2. On-time Arranged Interchange being transitioned to Confirmed Interchange without enough time to incorporate into scheduling systems prior to ramp start as specified in Attachment 1, Column D.~~

~~M5. The Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it distributed each Arranged Interchange to the listed entities and that for those distributions that exceed the times specified in Attachment 1, Column A, neither Part 1.1 or Part 1.2 occurred. (R1)~~

~~R2.~~R1. ~~With the exception of the provisions in R5, each Balancing Authority receiving an~~ on-time Arranged Interchange or ~~an~~ emergency Arranged Interchange ~~shall~~[2]

~~Rationale for R2: Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. R2.1 and R2.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny for other reasons. If the conditions described in R2.1 or R2.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.~~

~~[1] As defined in INT-006-4 Attachment 1.~~

~~[2] Balancing Authorities are not required to provide~~

~~approve or deny its transition to Confirmed Interchange~~ that it receives and shall do so prior to the expiration of the ~~reliability assessment~~time period defined ~~in the timing requirements~~ in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~2.1.~~1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

~~2.2.~~1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the scheduling path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

M1. ~~Unless otherwise addressed by the provisions in Requirement R4, each~~Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (~~R2~~R1)

Rationale for R2: TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides

~~Rationale for R3: TSPs must take action on a received Arranged Interchange within a certain time frame. R3.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in R3.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.~~

~~R3.~~R2. Each Transmission Service Provider ~~receiving an~~shall approve or deny each on-time Arranged Interchange or ~~an~~ emergency Arranged Interchange~~, shall~~[3] ~~approve or deny its transition to Confirmed Interchange~~ that it receives and shall do so prior to the expiration of the ~~reliability assessment~~time period defined ~~in the timing requirements~~ in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~3.1.~~2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M2. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. If the transmission path between the

~~[3] Transmission Service Providers are not required to provide responses to any other requests.~~

Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (~~R3~~R2)

~~R4.~~R3. ~~Each~~The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the ~~reliability assessment~~time period defined ~~in the timing requirements~~ in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~4.1.~~3.1. If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.

~~M4.~~ M3. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request or that it communicated denial to the Reliability Coordinator no more than 10 minutes after the denial. (~~R4~~R3)

~~R5.~~R4. Each Sink Balancing Authority shall ~~not transition~~confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange ~~under any of the following conditions~~: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

- It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

M4. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that, under the conditions in ~~R5.1, R5.2, or R5.3~~R4, it did not transition an Arranged Interchange to Confirmed Interchange. (R4)

~~R6.~~R5. ~~Each Sink Balancing Authority shall distribute all notifications of whether an~~For each Arranged Interchange ~~was~~that is transitioned to Confirmed Interchange ~~to~~, the Sink Balancing Authority shall notify the following entities~~, and notifications~~ of the on-time Confirmed Interchange ~~shall be distributed~~ such that ~~they are~~the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~6.1.~~5.1. The Source Balancing Authority,

~~6.2.~~5.2. Each Intermediate Balancing Authority,

~~6.3.~~5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,

~~6.4.~~5.4. Each Transmission Service Provider included in the Arranged Interchange, and

~~6.5.~~5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

M5. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it ~~distributed notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to~~notified the ~~listed~~ entities~~, and that for an~~ of the on-time Confirmed Interchange~~,~~ such that the ~~distribution was~~notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D. (~~R6~~R5)

B. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, R4, ~~R5,~~ and ~~R6~~R5 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R3 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R1~~	~~Operations Planning, Same-day Operations, Real-time Operations~~	~~Medium~~	~~N/A~~	~~N/A~~	~~The Sink Balancing Authority did not distribute an Arranged Interchange to all of the entities listed in the requirement.~~	~~The Sink Balancing Authority did not distribute an Arranged Interchange to any of the entities listed in the requirement.~~ ~~OR~~ ~~The Sink Balancing Authority distributed an Arranged Interchange exceeding the times specified in Attachment 1 Column A that resulted in one or more of the conditions described in Requirement R1 Parts 1.1 and 1.2.~~
~~R2~~R1	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	~~When not subject to the provisions in Requirement R5, the~~The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny its transition to Confirmed Interchange prior to the expiration of the ~~reliability assessment~~time period defined ~~in the timing requirements~~ in Attachment 1,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange. OR The scheduling path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange.
~~R3~~R2	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny its transition to Confirmed Interchange prior to the expiration of the ~~reliability assessment~~time period defined~~ in the timing requirements~~ in Attachment 1,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
~~R4~~R3	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	~~The~~The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the ~~reliability assessment~~time period defined ~~in the timing requirements~~ in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.	~~The~~The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the ~~reliability assessment~~time period defined in ~~the timing requirements in~~ Attachment 1, Column B.
~~R5~~R4	Operations Planning, Same-day Operations, Real-time	Lower	N/A	N/A	N/A	~~One~~The Sink Balancing Authority failed to confirm that none of the conditions in Requirement ~~5 Parts 5.1, 5.2, or 5.3 was met, and the Sink~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Operations					~~Balancing Authority transitioned~~4 existed before transitioning an Arranged Interchange to Confirmed Interchange.
~~R6~~R5	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Sink Balancing Authority did not ~~distribute notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to~~notify all of the entities listed in Requirement ~~R6~~R5 Parts ~~6~~5.1-~~6.5.~~5.5 of the on-time Confirmed Interchange.	The Sink Balancing Authority did not ~~distribute notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to any of the~~ notify the entities listed in Requirement ~~R6~~R5 Parts ~~6~~5.1-~~6.5~~5.5 of the on-time Confirmed Interchange. OR The Sink Balancing Authority ~~distributed notifications of whether an Arranged Interchange was transitioned to~~notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not ~~distribute~~notify the ~~notifications such that they were delivered~~entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Attachment 1 – Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [4] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[5]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[5]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	~~≤ 1 minute from receipt~~	Entities have up to 2 hours to respond.	~~≤ 1 minute from receipt of all Reliability Assessments~~	NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late	~~≤ 1 minute from receipt~~	Entities have up to 10 minutes to respond.	~~≤ 1 minute from receipt of all Reliability Assessments~~	≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time	~~≤ 1 minute from receipt~~	≤ 10 minutes from Arranged Interchange receipt	~~≤ 1 minute from receipt of all Reliability Assessments~~	≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time	~~≤ 1 minute from receipt~~	≤ 20 minutes from Arranged Interchange receipt	~~≤ 1 minute from receipt of all Reliability Assessments~~	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	~~≤ 1 minute from receipt~~	≤ 2 hours from Arranged Interchange receipt	~~≤ 1 minute from receipt of all Reliability Assessments~~	≥ 1 hour 58 minutes prior to ramp start

[4] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

~~[5] Times are for software performance specifications, only.~~ [5] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

[redacted] Attachment 1 – Timing Tables

[redacted]

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [6] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[7]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[7]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	~~≤ 1 minute from receipt~~	Entities have up to 2 hours to respond.	~~≤ 1 minute from receipt of all Reliability Assessments~~	NA
<10 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is at the top of the hour	Late	~~≤ 1 minute from receipt~~	Entities have up to 10 minutes to respond.	~~≤ 1 minute from receipt of all Reliability Assessments~~	≤ 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is not the top of the hour	Late	~~≤ 1 minute from receipt~~	Entities have up to 10 minutes to respond.	~~≤ 1 minute from receipt of all Reliability Assessments~~	≤ 3 minutes after receipt of Confirmed Interchange
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time	~~≤ 1 minute from receipt~~	≤ 5 minutes from Arranged Interchange receipt	~~≤ 1 minute from receipt of all Reliability Assessments~~	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of	On-time	~~≤ 1 minute from receipt~~	≤ 6 minutes from Arranged Interchange receipt	~~≤ 1 minute from receipt of all Reliability Assessments~~	≥ 3 minutes prior to ramp start

[6] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

~~[7] Times are for software performance specifications, only.~~ [7] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If Arranged Interchange [6] is Submitted	Time Classification	Sink BA Makes Initial Distribution of Arranged Interchange [7]	BA and TSP Conduct Reliability Assessments	Compilation and Distribution Status [7]	BA Prepares Confirmed Interchange for Implementation
the hour					
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time	~~≤ 1 minute from receipt~~	≤ 7 minutes from Arranged Interchange receipt	~~≤ 1 minute from receipt of all Reliability Assessments~~	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time	~~≤ 1 minute from receipt~~	≤ 8 minutes from Arranged Interchange receipt	~~≤ 1 minute from receipt of all Reliability Assessments~~	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time	~~≤ 1 minute from receipt~~	≤ 9 minutes from Arranged Interchange receipt	~~≤ 1 minute from receipt of all Reliability Assessments~~	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time	~~≤ 1 minute from receipt~~	≤ 10 minutes from Arranged Interchange receipt	~~≤ 1 minute from receipt of all Reliability Assessments~~	≥ 3 minutes prior to ramp start
≥ 1 hour and < 4 hours prior to ramp start	On-time	~~≤ 1 minute from receipt~~	< 20 minutes from Arranged interchange receipt	~~≤ 1 minute from receipt of all Reliability Assessments~~	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	~~≤ 1 minute from receipt~~	≤ 2 hours from Arranged Interchange receipt	~~≤ 1 minute from receipt of all Reliability Assessments~~	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time	~~≤ 1 minute from receipt~~	By 12:00 PPT of day the Arranged Interchange was received	~~≤ 1 minute from receipt of all Reliability Assessments~~	≥ 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - All reliability entities involved in the Arranged Interchange are valid.
    - Generation source and load sink are defined.
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
    - Distribute notification as each entity approves or denies an Arranged Interchange.
    - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
    - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

- Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
  - Receive distribution of Arranged Interchange
  - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
  - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
  - Submit a request to modify Interchange

- While interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
  - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
  - How to notify others that it is activating the plan
  - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
  - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
  - Delegation of approval rights and proxy actions, if such approaches will be used.
  - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
  - Personnel plans for short-term and extended periods.
  - Training of personnel in the use of the plan.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

Description of Current Draft

This is the third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	September – October 2013
Recirculation ballot	December2013
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed revisions to existing definitions (redlined to show changes):

Dynamic Interchange Schedule or Dynamic Schedule: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in real time and ~~used~~ included in the Net Interchange Scheduled term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes). ~~as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.~~

Pseudo-tie: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in real time and included in the Net Interchange Actual term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).~~used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.~~

Adjacent Balancing Authority - A Balancing Authority Area whose Balancing Authority Area ~~that~~ is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

Confirmed Interchange - The state where no party has denied and all required parties have approved ~~the Interchange Authority has verified~~ the Arranged Interchange.

Proposed new definitions:

Attaining Balancing Authority: A Balancing Authority bringing generation or load into its effective control boundaries through a dynamic transfer from the Native Balancing Authority.

Native Balancing Authority: A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a dynamic transfer.

Composite Confirmed Interchange – The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Implementation of Interchange**
2. **Number:** **INT-009-2**
3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process and maintain the generation-to-load balance.
4. **Applicability:**

   4.1. Balancing Authority.

5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.

   The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term "Composite Confirmed Interchange" has been introduced.

   The content of INT-009-2 has been revised and expanded in the following manner:

   - R1 was combined with INT-003-3 R1 and modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.
   - R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Net Interchange Actual term for their ACE controls.
   - R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls a high-voltage direct current tie coordinates the Confirmed Interchange.

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any interchange as directed by a Reliability Coordinator per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and including any interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations*]

Rationale for R2: R12.3 of BAL-005-2b addresses common metering for Dynamic Schedules and Pseudo-Ties but not their implementation into ACE. Requirement R2 is equivalent to R10 of BAL-005-2b which addresses Dynamic Schedules.

M2. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process). (R2)

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie if applicable. [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2 and R3 for the most recent 3 months plus the current month.

If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, excluding Dynamic Schedules and including any interchange as directed by a Reliability Coordinator per INT-010-2 not yet captured in the Composite Confirmed Interchange, for that hour.
R2	Real Time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process).
R3	Real Time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

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Development Steps Completed

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Anticipated Actions	Anticipated Date
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BOT adoption	~~November 2013~~ February 2014
File standard with regulatory authorities.	~~December 2013~~February 2014

Effective Dates

~~First~~The first day of the ~~second~~first calendar quarter ~~beyond~~that is six months after the date that this standard is approved by an applicable ~~regulatory authorities, or~~governmental authority or as otherwise provided for in ~~those jurisdictions~~a jurisdiction where ~~regulatory~~ approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard ~~becomes~~shall become effective on the first day of the ~~second~~first calendar quarter ~~beyond~~that is six months after the date this standard is ~~approved~~adopted by the NERC Board of Trustees~~,~~ or as otherwise ~~made effective pursuant to the laws applicable to such ERO governmental authorities.~~provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. ~~New or revised definitions listed below become approved when the proposed standard is approved.~~ When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed revisions to existing definitions (redlined to show changes):

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Pseudo-~~Tie~~tie: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in real time and included in the Net Interchange Actual term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).~~used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.~~

Adjacent Balancing Authority - A Balancing Authority Area whose Balancing Authority Area ~~that~~ is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

Confirmed Interchange - The state where no party has denied and all required parties have approved ~~the Sink BalancingInterchange Authority has verified~~ the Arranged Interchange.

~~**Composite Confirmed Interchange** – The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.~~

Proposed new definitions:

Attaining Balancing Authority: A Balancing Authority bringing generation or load into its effective control boundaries through a dynamic transfer from the Native Balancing Authority.

Native Balancing Authority: A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a dynamic transfer.

Composite Confirmed Interchange – The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Implementation of Interchange**

2. **Number: INT-009-2**

3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process and maintain the generation-to-load balance.

4. **Applicability:**

   4.1. Balancing Authority.

5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.

   The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term "Composite Confirmed Interchange" has been introduced.

   The content of INT-009-2 has been revised and expanded in the following manner:

   - R1 was combined with INT-003-3 R1 and modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.
   - R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Net Interchange Actual term for their ACE controls.
   - R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls ~~an HVDC~~a high-voltage direct current tie coordinates the Confirmed Interchange.

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any interchange as directed by a Reliability Coordinator per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and including any interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations*]

Rationale for R2: R12.3 of BAL-005-2b addresses common metering for Dynamic Schedules and Pseudo-Ties but not their implementation into ACE. Requirement R2 is equivalent to R10 of BAL-005-2b which addresses Dynamic Schedules.

M2. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process). (R2)

R3. Each Balancing Authority in whose area the ~~HVDC~~high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the ~~HVDC~~high-voltage direct current tie if applicable. [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the ~~HVDC~~high-voltage direct current tie. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2 and R3 for the most recent 3 months plus the current month.

If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit~~s~~

Self-Certification~~s~~

Spot Checking

Compliance Investigation

Self-Reporting

Complaint~~s~~

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, excluding Dynamic Schedules and including any interchange as directed by a Reliability Coordinator per INT-010-2 not yet captured in the Composite Confirmed Interchange, for that hour.
R2	Real Time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process).
R3	Real Time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the ~~HVDC~~high-voltage direct current tie.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

Description of Current Draft

This is the third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	September – October 2013
Recirculation ballot	December 2013
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD		New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed revisions to existing definitions (redlined to show changes):

Request for Interchange (RFI) - A collection of data as defined in the NAESB Business Practice Standards ~~RFI Datasheet,~~ to be submitted to the ~~Interchange~~ Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.

Confirmed Interchange - The state where no party has denied and all required parties have approved ~~the Interchange Authority has verified~~ the Arranged Interchange.

Dynamic Interchange Schedule or Dynamic Schedule: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in real time and ~~used~~ included in the Net Interchange Scheduled term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes). ~~as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.~~

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule. ~~(This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)~~

Proposed new definitions:

Reliability Adjustment Arranged Interchange - Request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Interchange Initiation and Modification for Reliability**
2. **Number:** **INT-010-2**
3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.
4. **Applicability:**

   4.1. Balancing Authority

   4.2.
5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to replace “request for Arranged Interchange” with the correct term “Request for Interchange”.
   - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.
   - R4 was created to address the fact that when a Reliability Adjustment Arranged Interchange is approved for a Pseudo-Tie or Dynamic Schedule, action is required by the Balancing Authority to ensure that the data source feeding the Net Interchange value of ACE value does not exceed the MW value of the Reliability Adjustment Arranged Interchange.

B. Requirements and Measures

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted an RFI per Requirement R1. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting that modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed

Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was created within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a RFI was created reflecting that Interchange schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

R4. Each Balancing Authority involved in a Pseudo-Tie or Dynamic Schedule shall ensure the MW value from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange is not exceeded in their ACE equation. [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations*]

Rationale for R1: The Balancing Authority is responsible for implementing the Confirmed Interchange that results from a Reliability Adjustment Arranged Interchange. Future actions may be taken by the Balancing Authority or other entities that may reduce or eliminate the curtailment.

M4. The Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that, following any Reliability Adjustment Arranged Interchange on a Pseudo-Tie or Dynamic Schedule, it ensured the MW value from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange was not exceeded in their ACE equation. (R4)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, R3, and R4for the most recent three calendar months plus the current month.
- If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement did not ensure that a RFI was submitted following the resource loss.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting the modification was submitted within 60 minutes following the start of the modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a RFI was submitted within 60 minutes following the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						start of the scheduled Interchange.
R4	Real Time Operations	Lower	N/A	N/A	N/A	The Balancing Authority involved in a Pseudo-Tie or Dynamic Schedule failed to ensure that the MW value from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange was not exceeded in its ACE equation.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

In NERC's Dynamic Transfer Reference Guidelines, Version 2, it describes unique handling of curtailments of dynamic transfers.

For Dynamic Schedules:

> **If transmission service between the source and sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as dynamic transfer signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-ties:

> **If transmission service between the native and attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe that when curtailments (typically communicated through e-Tags) of dynamic transfers occur, they require additional action by Balancing Authorities to ensure compliance with the curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including curtailments, in Dynamic Schedule and Pseudo-tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the dynamic transfer signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the dynamic transfer signal in order to comply with the curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

Description of Current Draft

This is the ~~second~~third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	~~July~~September – October 2013
Recirculation ballot	~~October~~December 2013
BOT adoption	~~November 2013~~February 2014
File standard with regulatory authorities.	~~December 2013~~February 2014

Effective Dates

~~First~~The first day of the ~~second~~first calendar quarter ~~following~~that is six months after the date that this standard is approved by an applicable ~~regulatory authorities,~~governmental authority or as otherwise provided for in ~~those jurisdictions~~a jurisdiction where ~~regulatory~~ approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard ~~becomes~~shall become effective on the first day of the ~~second~~first calendar quarter that is six months after the date this standard is ~~approved~~adopted by the NERC Board of Trustees~~.~~ or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD		New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. ~~New or revised definitions listed below become approved when the proposed standard is approved.~~ When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed revisions to existing definitions (redlined to show changes):

Request for Interchange (RFI) - A collection of data as defined in the NAESB Business Practice Standards ~~RFI Datasheet,~~ to be submitted to the ~~Interchange~~ Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.

Confirmed Interchange - The state where no party has denied and all required parties have approved ~~the Sink BalancingInterchange Authority has verified~~ the Arranged Interchange.

> **~~Reliability Adjustment Arranged~~ Dynamic Interchange** ~~- Request to modify a Confirmed Interchange~~**Schedule or** ~~Implemented Interchange for reliability purposes.~~

Dynamic Schedule: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in real time and ~~used~~ included in the Net Interchange Scheduled term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes). ~~as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.~~

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule. ~~(This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)~~

Proposed new definitions:

Reliability Adjustment Arranged Interchange - Request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Interchange Initiation and Modification for Reliability**
2. **Number:** **INT-010-2**
3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability ~~events~~.
4. **Applicability:**

    4.1. Balancing Authority

    ~~**4.2.** Transmission Service Provider~~

    ~~**4.3.**~~**4.2.** ~~Reliability Coordinator~~

5. **Background:**

    This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

    - R1 is modified to ~~eliminate the prerequisite that a Balancing Authority experience a loss of resources covered by an energy sharing agreement with respect to requirement applicability.~~replace "request for Arranged Interchange" with the correct term "Request for Interchange".
    - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.
    - ~~R4 is created to ensure that Reliability Adjustment Arranged Interchanges are initiated only for reliability related reasons.~~
    - ~~R5 was created from INT-005-3 R1.1 describing the restricted list of entities that have approval rights on a Reliability Adjustment Arranged Interchange~~
    - ~~R6~~R4 was created to address the fact that when a Reliability Adjustment Arranged Interchange is approved for a Pseudo-Tie or Dynamic Schedule, action is required by the Balancing Authority to ensure that the data source feeding the Net Interchange value of ACE value ~~is adjusted in accordance~~does not exceed the MW value of the Reliability Adjustment Arranged Interchange.

B. Requirements and Measures

R1. ~~Each Sink~~The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a Request for Interchange ~~is created within 60 minutes of the start of the energy sharing, and~~(RFI) is submitted with a start time no more than 60 minutes beyond the ~~start~~resource loss. If the use of the energy sharing ~~for Interchange scheduled in duration of more than 60 minutes as part of an energy sharing agreement,~~ agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M1. The ~~Sink~~ Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that ~~when it participated in energy sharing pursuant to the subject sharing agreement lasting longer than 60 minutes, it ensured that a RFI was created within 60 minutes of the start of the energy sharing, and with a start time no more than 60 minutes beyond the start of the energy sharing.~~it submitted an RFI per Requirement R1. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting that modification is ~~created~~submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was created within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is ~~created~~submitted reflecting that Interchange schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a RFI was created reflecting that Interchange schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

~~**R4.**~~ Each ~~Reliability Coordinator,~~ Balancing Authority involved in a Pseudo-Tie or ~~Transmission Service Provider that initiates~~Dynamic Schedule shall ensure the MW value from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange ~~must have experienced one or more of the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]~~

Rationale for R1: The Balancing Authority is responsible for implementing the Confirmed Interchange that results from a Reliability Adjustment Arranged Interchange. Future actions may be taken by the Balancing Authority or other entities that may reduce or eliminate the curtailment.

~~**4.1.** The loss or non-performance of generation supplying the Interchange.~~

~~**4.2.** The loss of Load served by the Interchange.~~

~~**4.3.** The loss of one or more Transmission Facilities.~~

~~**4.4.** An actual or potential System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance.~~

~~**4.5.** Any real-time reliability concern related to a specific Confirmed Interchange.~~

~~**M4.** Each applicable entity shall have evidence such as dated and time-stamped logs, voice recordings, electronic records, or other similar evidence that when it created a Reliability Adjustment Arranged Interchange subject to this requirement, one or more of the following were true: generation supplying the Interchange was lost or did~~is not ~~perform; Load being served by the Interchange was lost; one or more Transmission Facilities were lost; an actual or potential SOL or IROL exceedance was experienced; or the entity experienced a real-time reliability concern related to a specific confirmed Interchange. (R4)~~

~~**R5.**~~**R4.** ~~Each Sink Balancing Authority shall distribute any Reliability Adjustment Arranged Interchange only to the Source Balancing Authority for reliability assessment.~~exceeded in their ACE equation. [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations*]

~~**M5.**~~**M4.** The ~~Sink~~ Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that ~~it distributed~~, following any Reliability Adjustment Arranged Interchange ~~only to~~on a Pseudo-Tie or Dynamic Schedule, it ensured the ~~Source Balancing Authority for reliability assessment. (R5~~MW value from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange was not exceeded in their ACE equation. (R4)

~~**R6.** Each Balancing Authority involved in a Reliability Adjustment Arranged Interchange involving a Dynamic Schedule shall use agreed upon values that ensure any limit established by the Reliability Adjustment Arranged Interchange is not exceeded. [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations*]~~

~~**M6.** The Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that following any Reliability Adjustment Arranged Interchange involving a Dynamic Schedule it used agreed upon values that ensured any limit established by the Reliability Adjustment Arranged Interchange was not exceeded. (R6)~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, R3, ~~R4, R5~~ and ~~R6 for~~R4for the most recent three calendar months plus the current month.
- ~~The Reliability Coordinator and Transmission Service provider shall maintain evidence to show compliance with R4 for the most recent three calendar months plus the current month.~~
- If a ~~Reliability Coordinator,~~ Balancing Authority~~, or Transmission Service Provider~~ is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit~~s~~

Self-Certification~~s~~

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Real Time Operations	Lower	The ~~Sink~~ Balancing Authority that experienced a loss of resources covered by an energy sharing agreement ensured that a Request for Interchange was ~~created~~submitted, and it was ~~created~~submitted with a start time more than 60 minutes, but not more than 75 minutes, following the ~~start of the energy sharing~~resource loss.	The ~~Sink~~ Balancing Authority that experienced a loss of resources covered by an energy sharing agreement ensured that a Request for Interchange was ~~created~~submitted, and it was ~~created~~submitted with a start time more than 75 minutes, but not more than 90 minutes, following the ~~start of the energy sharing~~resource loss.	The ~~Sink~~ Balancing Authority that experienced a loss of resources covered by an energy sharing agreement ensured that a Request for Interchange was ~~created~~submitted, and it was ~~created~~submitted with a start time more than 90 minutes, but not more than 120 minutes, following the ~~start of the energy sharing~~resource loss.	The ~~Sink~~ Balancing Authority that experienced a loss of resources covered by an energy sharing agreement ensured that ~~the~~a Request for Interchange was ~~created~~submitted, and it was ~~created~~submitted with a start time more than 120 minutes following the ~~start of the energy sharing~~resource loss. OR The ~~Sink~~ Balancing Authority that experienced a loss of resources covered by an energy sharing agreement did not ensure that a RFI was ~~created~~submitted following the ~~start of the energy sharing.~~resource loss.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting the modification was ~~created~~submitted within 60 minutes following the start of the modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						a RFI was ~~created~~submitted within 60 minutes following the start of the scheduled Interchange.
~~R4~~	~~Operations Planning, Same Day Operations, Real Time Operations~~	~~Lower~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity initiated a Reliability Adjustment Arranged Interchange and did not experience one of the elements listed in Requirement R4 Parts 4.1 – 4.5.~~
~~R5~~	~~Real Time Operations~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity failed to distribute any Reliability Adjustment Arranged Interchange to the Source Balancing Authority for reliability assessment.~~
~~R6~~R4	Real Time Operations	Lower	N/A	N/A	N/A	The ~~responsible entity~~ Balancing Authority involved in a Pseudo-Tie or Dynamic Schedule failed to ~~use an agreed upon~~ensure that the MW value ~~that ensured any limit established by the~~from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange ~~involving a Dynamic Schedule is~~was not exceeded in its ACE

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						equation.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

In NERC's Dynamic Transfer Reference Guidelines, Version 2, it describes unique handling of curtailments of dynamic transfers.

For Dynamic Schedules:

> **If transmission service between the source and sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as dynamic transfer signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-ties:

> **If transmission service between the native and attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe that when curtailments (typically communicated through e-Tags) of dynamic transfers occur, they require additional action by Balancing Authorities to ensure compliance with the curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including curtailments, in Dynamic Schedule and Pseudo-tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the dynamic transfer signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the dynamic transfer signal in order to comply with the curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
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4. SDT appointed (February 12, 2009).
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7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

Description of Current Draft

This is the third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	September - October 2013
Recirculation ballot	December 2013
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Adopted by the NERC Board of Trustees	New standard developed

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed revision to existing definition:

Request for Interchange (RFI) - A collection of data as defined in the NAESB Business Practice Standards ~~RFI Datasheet,~~ to be submitted to the ~~Interchange~~ Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

NOTE: In November 2009, the Coordinate Interchange Standards Drafting Team (CISDT) posted a proposed new standard: INT-011-1—Interchange Coordination Support. That standard focused on the electronic capabilities required of entities for supporting Interchange coordination. After reviewing stakeholder comments on that posting and discussing the standard further, the CISDT determined that its contents would be better suited for the guideline and technical basis section of proposed INT-006-4. Because INT-011-1—Interchange Coordination Support never went before NERC's Board of Trustees or FERC, the CISDT is reusing the INT-011-1 number here, for INT-011-1—Intra-Balancing Authority Transaction Identification.

A. Introduction

1. **Title:** **Intra-Balancing Authority Transaction Identification**
2. **Number:** **INT-011-1**
3. **Purpose:** To ensure that transfers within a Balancing Authority Area using Point to Point Transmission Service are communicated and accounted for in congestion management procedures.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Load-Serving Entities
5. **Background:**

   This standard was created in response to a FERC directive in Order 693, paragraph 817: *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

   The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

B. Requirements and Measures

R1. Each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange unless the information about intra-Balancing Authority transfers is included in congestion

management procedure(s) via an alternate method. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations]*

M1. Each Load-Serving Entity subject to R1 shall have evidence, such as dated and time-stamped electronic records, documentation of congestion management procedures, or other similar evidence, that a Request for Interchange was submitted for each Point to Point Transmission Service intra-Balancing Authority transfer subject to R1 or that each intra-Balancing Authority transfer subject to R1 was accounted for in congestion management procedure(s) via an alternate method. (R1)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Load-Serving Entity shall keep data or evidence to show compliance with R1 for the most recent three months plus the current month unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	*Operations Planning, Same-day Operations*	*Lower*	N/A	N/A	N/A	The Load-Serving Entity used Point to Point Transmission Service for an intra-Balancing Authority Area transfer, and did not submit a Request for Interchange for an intra-Balancing Authority transfer that is not included in congestion management procedure(s) via an alternate method.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

Description of Current Draft

This is the ~~second~~third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	~~July~~September - October 2013
Recirculation ballot	~~October~~December 2013
BOT adoption	~~November 2013~~February 2014
File standard with regulatory authorities.	~~December 2013~~February 2014

Effective Dates

~~First~~The first day of the ~~second~~first calendar quarter ~~beyond~~that is six months after the date that this standard is approved by an applicable ~~regulatory authorities, or~~governmental authority or as otherwise provided for in ~~those jurisdictions~~a jurisdiction where ~~regulatory~~ approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard ~~becomes~~shall become effective on the first day of the ~~second~~first calendar quarter ~~beyond~~that is six months after the date this standard is ~~approved~~adopted by the NERC Board of Trustees~~,~~ or as otherwise ~~made effective pursuant to the laws applicable to such ERO governmental authorities.~~provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Adopted by the NERC Board of Trustees	New standard developed

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. ~~New or revised definitions listed below become approved when the proposed standard is approved.~~ When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed revision to existing definition:

Request for Interchange (RFI) - A collection of data as defined in the NAESB Business Practice Standards ~~RFI Datasheet,~~ to be submitted to the ~~Interchange~~ Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

NOTE: In November 2009, the Coordinate Interchange Standards Drafting Team (CISDT) posted a proposed new standard: INT-011-1—Interchange Coordination Support. That standard focused on the electronic capabilities required of entities for supporting Interchange coordination. After reviewing stakeholder comments on that posting and discussing the standard further, the CISDT determined that its contents would be better suited for the guideline and technical basis section of proposed INT-006-4. Because INT-011-1—Interchange Coordination Support never went before NERC's Board of Trustees or FERC, the CISDT is reusing the INT-011-1 number here, for INT-011-1—Intra-Balancing Authority Transaction Identification.

A. Introduction

1. **Title:** **Intra-Balancing Authority Transaction Identification**

2. **Number:** **INT-011-1**

3. **Purpose:** To ensure that transfers within a Balancing Authority Area using Point to Point Transmission Service are communicated and accounted for in congestion management procedures.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Load-Serving Entities

5. **Background:**

   This standard was created in response to a FERC directive in Order 693, paragraph 817: *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

   The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

B. Requirements and Measures

R1. Each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange unless the information about intra-Balancing Authority transfers is included in congestion

management procedure(s) via an alternate method. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations]*

M1. Each Load-Serving Entity subject to R1 shall have evidence, such as dated and time-stamped electronic records, documentation of congestion management procedures, or other similar evidence, that a Request for Interchange was submitted for each ~~intra-Balancing Authority transfer subject~~Point to ~~R1~~ Point Transmission Service intra-Balancing Authority transfer subject to R1 or that each intra-Balancing Authority transfer subject to R1 was accounted for in congestion management procedure(s) via an alternate method. (R1)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Load-Serving Entity shall keep data or evidence to show compliance with R1 for the most recent three months plus the current month unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit~~s~~

Self-Certification~~s~~

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	*Operations Planning, Same-day Operations*	*Lower*	N/A	N/A	N/A	The Load-Serving Entity used Point to Point Transmission Service for an intra-Balancing Authority Area transfer, and did not submit a Request for Interchange for an intra-Balancing Authority transfer that is not included in congestion management procedure(s) via an alternate method.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Implementation Plan

Project 2008-12: Coordinate Interchange Standards

Requested Approvals

- INT-004-3 — Dynamic Transfers
- INT-006-4 — Evaluation of Interchange Transactions
- INT-009-2 — Implementation of Interchange
- INT-010-2 — Interchange Initiation and Modification for Reliability
- INT-011-1 — Intra-Balancing Authority Transaction Identification

Requested Retirements

- INT-001-3 Interchange Information
- INT-003-3 Interchange Transaction Implementation
- INT-004-2 Dynamic Interchange Transaction Modifications
- INT-005-3 Interchange Authority Distributes Arranged Interchange
- INT-006-3 Response to Interchange Authority
- INT-007-1 Interchange Confirmation
- INT-008-3 Interchange Authority Distributes Status
- INT-009-1 Implementation of Interchange
- INT-010-1 Interchange Coordination Exemptions

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

- **Dynamic Interchange Schedule or Dynamic Schedule:** A time-varying energy transfer that is updated in real time and included in the Net Interchange Scheduled term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Pseudo-Tie:** A time-varying energy transfer that is updated in real time and included in the Net Interchange Actual term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

- **Request for Interchange** - A collection of data as defined in the NAESB Business Practice Standards, to be submitted to the Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.
- **Arranged Interchange** - The state where the Sink Balancing Authority has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).
- **Confirmed Interchange** - The state where no party has denied and all required parties have approved the Arranged Interchange.
- **Adjacent Balancing Authority** - A Balancing Authority whose Balancing Authority Area that is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
- **Intermediate Balancing Authority** - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
- **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule.
- **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for the resulting Interchange Schedule.
- **Operational Planning Analysis:** An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Proposed additional Defined Terms to be added to the NERC Glossary

- **Reliability Adjustment Arranged Interchange** - Request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
- **Composite Confirmed Interchange –** The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
- **Attaining Balancing Authority:** A Balancing Authority bringing generation or load into its effective control boundaries through a dynamic transfer from the Native Balancing Authority.
- **Native Balancing Area:** A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a dynamic transfer.

Background

The standards were developed under Project 2008-12, Coordinate Interchange Standards. The drafting team revised the existing approved standards and grouped the requirements in distinct groupings within each standard. The drafting team developed a new standard, INT-011-1, Intra-Balancing Authority Transaction Identification, in response to a FERC directive in Order 693, paragraph 817:

> *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

The proposed revision to the definition of Operational Planning Analysis addresses a FERC Order 693 directive:

> *866. Accordingly, the Commission approves Reliability Standard INT-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.*

The Reliability Coordinator and Transmission Operator are required to perform an Operational Planning Analysis in existing IRO-008-1, Requirement R1 and in TOP-002-3, Requirement R1 which was filed with FERC on April 16, 2013. By including the term "Interchange" explicitly in the definition, the drafting team has addressed the directive.

Applicable Entities

- Balancing Authority
- Transmission Service Provider
- Load-Serving Entities

Effective Date

First day of the second calendar quarter beyond the date each standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date each standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

Midnight of the day immediately prior to the Effective Date of the new standards in the particular jurisdiction in which the new standards are becoming effective.

Implementation Plan for Definitions

Entities shall use all proposed definitions when implementing any requirements within the new standards which use the defined term(s).

Implementation Plan for INT-004-3, Requirement R3

Requirement R3 is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. A request to revise the NAESB Electric Industry Registry has already been submitted for implementation. This requirement will become effective on the first calendar day one calendar quarter after the NAESB Electric Industry Registry is able to accept Pseudo-Tie registrations. All existing and future Pseudo-Ties are to be registered in the NAESB Electric Industry Registry.

Unofficial Comment Form

Project 2008-12 Coordinate Interchange Standards

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the standards and associated documents. The electronic comment form must be completed by **8:00 p.m. ET, November 13, 2013**. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

If you have questions please contact Steve Crutchfield (via email) or by telephone at 609-651-9455.

Project 2008-12: Coordinate Interchange Standards Project Page

Background Information

The Coordinate Interchange Standard Drafting Team posted drafts of INT-004-3, INT-006-4, INT-009-2, INT-010-2, and INT-011-1 for a 30-day public comment period from July 25 – August 23, 2013. The posting was designed to gather stakeholder feedback regarding the proposed requirements, especially with respect to the aspects of Paragraph 81 criteria. The drafting team did not get clear consensus with respect to the requirements. The drafting team considered each of the comments and have incorporated those that team found to improve the quality of the standards. Below is a list of the changes made to the standards since the last posting.

INT-004

- R1: An exception for Pseudo-ties that are already accounted for in congestion management tools was added and the detail on the MW amount to be included on the transaction was eliminated.
- R2: The requirement was revised to apply to only those LSEs that submitted and RFI per R1. The drafting team also simplified the language or R2.1 and R2.2 and R2.3.
- R3: This was removed as an interim registration process was determined to be unnecessary.
- R4: The requirement was modified to require entities to register Pseudo-Ties when the registration process is available in the NAESB Electric Industry Registry (EIR).
- The drafting team added general considerations for curtailment of dynamic transactions to the Guidelines and Technical Basis section of the standard.

INT-006

- R1: This requirement was removed. The entities to receive the transaction are included today in the eTag specification, Section 3.6.1.1.1. The timing requirement for the distribution of tags is removed from this standard, as they are currently included and expected to remain in the NAESB documentation.

- R2, R3: The drafting team revised the language for clarity.
- R4: The drafting team added the specific entities to perform the review.
- R5: No changes. These requirements direct that 'active' approval is required to transition to Confirmed Interchange; that if entities do not approve the transaction that it will not be transitions to Confirmed. If the software were not automatically performing this function, this requirement identifies the logic to be applied.
- R6: No changes. This distribution requirement may currently drive how software performs this function. However, if that software were not present this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the interchange to occur.
- Tables: The drafting team removed columns A and C details as these are no addressed in any requirement. These details remain in the NAESB timing tables.

INT-009

- R1: The drafting team added phrase "by a Reliability Coordinator" to clarify what aspect of INT-010 is applicable to this requirement.
- R2: No change was made to language but language was added to the Rationale.
- R3: This requirement was unchanged and was not removed as suggested by some commenters. Since the Transmission Operator is not a part of the approval process for the Interchange, this requirement is the only means by which they are aware of the need to adjust the HVDC flow.

INT-010

- R1: This language was modified to be consistent with the currently effective requirement. This results in minimal revision to the existing, enforceable requirement.
- R2, R3: The drafting team revised the term "created" to "submitted".
- R4: The drafting team agreed with comments that these are rules for when reliability adjusts should be used and if reliability adjusts were issued for reasons other than this it would not impact reliability. We agree these would be included in the NAESB business and the requirement is removed from the standard.
- R5: The entities to receive the transaction for evaluation are included today in the eTag specification, Section 3.6.1.1.1 so the drafting team has removed this requirement.
- R6: Pseudo-ties were added to the requirement and the language was clarified.

- The drafting team added general considerations for curtailment of dynamic transactions to the Guidelines and Technical Basis section of the standard.

Several entities from the ERCOT area requested exemption from some or all of the standards. When the drafting team reviewed the requirements we did not see that an exemption is required. For example, on INT-011, if ERCOT does not have point-to-point service, the requirement would not apply and an exemption is not needed. However, when we look at INT-006, if ERCOT is involved in a transaction outside its area, all of these requirements would apply.

Proposed Revisions or Additions to NERC Glossary of Terms

1. Proposed revisions to approved NERC Glossary terms (*note that for stakeholder convenience, each term has been redlined in the list of definitions contained in each posted standard*) :

   a. **Adjacent Balancing Authority** - A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

      Existing definition: A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

   b. **Intermediate Balancing Authority -** A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.

      Existing Definition: A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.

   c. **Dynamic Interchange Schedule or Dynamic Schedule:** A time-varying energy transfer that is updated in real time and included in the Net Interchange Scheduled term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).

      Existing definition: A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.

   d. **Pseudo-tie:** A time-varying energy transfer that is updated in real time and included in the Net Interchange Actual term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

      Existing definition: A telemetered reading or value that is updated in real time and used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.

e. **Request for Interchange (RFI) -** A collection of data as defined in the NAESB Business Practice Standards, to be submitted to the Sink Balancing Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.

   Existing definition: A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.

f. **Arranged Interchange** - The state where the Sink Balancing Authority has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).

   Existing definition: The state where the Interchange Authority has received the Interchange information (initial or revised).

g. **Confirmed Interchange** - The state where no party has denied and all required parties have approved the Arranged Interchange.

   Existing definition: The state where the Interchange Authority has verified the Arranged Interchange.

h. **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and the resulting Interchange Schedule.

   Existing Definition: The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)

i. **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for the resulting Interchange Schedule.

   Existing Definition: The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)

2. Proposed new NERC Glossary terms:

   Composite Confirmed Interchange – The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.

   Attaining Balancing Authority - A Balancing Authority bringing generation or load into its effective control boundaries through a dynamic transfer from the Native Balancing Authority.

Native Balancing Authority - A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a dynamic transfer.
Reliability Adjustment Arranged Interchange - Request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

3. Proposed NERC Glossary terms for retirement:

   Sending Balancing Authority – The Balancing Authority exporting the Interchange.

   Receiving Balancing Authority -The Balancing Authority importing the Interchange.

   Reliability Adjustment RFI - Request to modify an Implemented Interchange Schedule for reliability purposes.

   The defined term Sending Balancing authority is only used in existing Standard INT-003-3 in Requirement R1. The CISDT has replaced this term with Source Balancing Authority. It is also contained in the defined terms Intermediate Balancing Authority and Source Balancing Authority. The CISDT has removed Sending Balancing Authority from those two defined terms.

   The defined term Receiving Balancing authority is only used in Standard INT-003-3 in Requirement R1. The CISDT has replaced this term with Sink Balancing Authority. It is also contained in the defined terms Intermediate Balancing Authority and Sink Balancing Authority. The CISDT has removed Receiving Balancing Authority from those two defined terms.

   The defined term Reliability Adjustment RFI is used in INT-006-3, Requirement R1. The CISDT has proposed a new defined term, Reliability Adjustment Arranged Interchange, as a replacement as it more appropriately defines the reliability activity.

4. Additional terms revised to address FERC directives:

   The CISDT had previously posted proposed requirements to address FERC Order 693, Paragraph 866. These proposed Transmission Operator and Reliability Coordinator requirements related to review of Confirmed Interchange prior to implementation. The CISDT received feedback from stakeholders as well the NERC Operating Committee that the proposed requirements were not necessary as this review was already addressed in other standards. The CISDT reviewed those standards and Interchange is not explicitly noted. The team feels that additional revisions are necessary to meet the directive. Rather than revise requirements, the CISDT is proposing revisions to defined terms as they apply to existing standards. These terms are Operational Planning Analysis and Real-time Assessment:

   Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.)

Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

This defined term is used in existing IRO-008-1 (Reliability Coordinator Operational Analyses and Real-time Assessments) and proposed TOP-002-3 (Operations Planning). In IRO-008-1, Requirement R1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis. By explicitly including “Interchange” in the definition of Operational Planning Analysis, the Reliability Coordinator must consider interchange when performing the study. Further, Requirement R2 specifies that the Reliability Coordinator must perform a Real-time Assessment. Again, by explicitly including “Interchange” in the definition of Real-time Assessment, the Reliability Coordinator must consider interchange when performing the study. When the results of either of these studies indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3. TOP-002-3 contains requirement for the Transmission Operator to perform an Operational Planning Analysis (R1), develop plans for reliable operations based on the results of the Operational Planning Analysis and to notify other entities as to their role in those plans (R3).

Questions

1. **INT-004-3**: Do you have any comments relating to INT-004-3? Please provide specific suggestions for improvement, including alternate language.

   ☐ Yes
   ☐ No
   Comments:

2. **INT-006-4**: Do you have any comments relating to INT-006-4? Please provide specific suggestions for improvement, including alternate language.

   ☐ Yes
   ☐ No
   Comments:

3. **INT-009-2**: Do you have any comments relating to INT-009-2? Please provide specific suggestions for improvement, including alternate language.

   ☐ Yes
   ☐ No
   Comments:

4. **INT-010-2**: Do you have any comments relating to INT-010-2? Please provide specific suggestions for improvement, including alternate language.

   ☐ Yes
   ☐ No
   Comments:

5. **INT-011-1**: A requirement was developed to require that each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange unless the information about intra-Balancing Authority transfers is included in congestion management procedure(s) via an alternate method. Do you agree with this proposed requirement? If not, please provide specific suggestions for improvements to the requirement.

   ☐ Yes
   ☐ No
   Comments:

6. **INT-011-1**: Do you have any other comments relating to INT-011-1 that you have not previously submitted? Please provide specific suggestions for improvement, including alternate language.

   ☐ Yes
   ☐ No
   Comments:

7. **Definitions**: The CISDT proposed revisions to the defined term Dynamic Schedule. Do you agree with the proposed revisions? If not, please provide specific suggestions for improvements.

   ☐ Yes
   ☐ No
   Comments:

8. **Definitions:** The CISDT proposed revisions to the defined term Pseudo-Tie. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

   ☐ Yes
   ☐ No
   Comments:

9. **Definitions**: The CISDT proposed revisions to the defined term Adjacent Balancing Authority. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

☐ Yes
☐ No
Comments:

10. **Definitions**: The CISDT proposed revisions to the defined term Arranged Interchange. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

☐ Yes
☐ No
Comments:

11. **Definitions**: The CISDT proposed revisions to the defined term Confirmed Interchange. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

☐ Yes
☐ No
Comments:

12. **Definitions**: The CISDT proposed revisions to the defined term Intermediate Balancing Authority. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

☐ Yes
☐ No
Comments:

13. **Definitions**: The CISDT proposed revisions to the defined term Request for Interchange (RFI). Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

☐ Yes
☐ No
Comments:

14. **Definitions**: The CISDT proposed revisions to the defined term Sink Balancing Authority. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

☐ Yes
☐ No
Comments:

15. **Definitions**: The CISDT proposed revisions to the defined term Source Balancing Authority. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

☐ Yes
☐ No
Comments:

16. **Definitions**: The CISDT proposed a new defined term, Reliability Adjustment Arranged Interchange which is a replacement for the current term Reliability Adjustment RFI. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

☐ Yes
☐ No
Comments:

17. **Definitions:** The CISDT proposed a new defined term Composite Confirmed Interchange. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

☐ Yes
☐ No
Comments:

18. **Definitions:** The CISDT proposed a new defined term Attaining Balancing Authority. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

☐ Yes
☐ No
Comments:

19. **Definitions:** The CISDT proposed a new defined term Native Balancing Area. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

☐ Yes
☐ No
Comments:

20. **FERC Directives from Order 693, Paragraph 866**: The CISDT has proposed revisions to the definition of Operational Planning Analysis. Do you agree with this proposed defined term? If not, please provide specific substantive suggestions for improvements to the definitions.

☐ Yes
☐ No
Comments:

VRFs and VSLs

21. **VRFs and VSLs for INT-004-3**: The CISDT has proposed Violation Risk Factors and Violation Severity Levels for this standard. Do you agree with these compliance elements? If not, please provide specific substantive suggestions for improvements to the VRFs or VSLs.

☐ Yes
☐ No
Comments:

22. **VRFs and VSLs for INT-006-4**: The CISDT has proposed Violation Risk Factors and Violation Severity Levels for this standard. Do you agree with these compliance elements? If not, please provide specific substantive suggestions for improvements to the VRFs or VSLs.

☐ Yes
☐ No
Comments:

23. **VRFs and VSLs for INT-009-2**: The CISDT has proposed Violation Risk Factors and Violation Severity Levels for this standard. Do you agree with these compliance elements? If not, please provide specific substantive suggestions for improvements to the VRFs or VSLs.

☐ Yes
☐ No
Comments:

24. **VRFs and VSLs for INT-010-2**: The CISDT has proposed Violation Risk Factors and Violation Severity Levels for this standard. Do you agree with these compliance elements? If not, please provide specific substantive suggestions for improvements to the VRFs or VSLs.

☐ Yes
☐ No
Comments:

25. **VRFs and VSLs for INT-011-1:** The CISDT has proposed Violation Risk Factors and Violation Severity Levels for this standard. Do you agree with these compliance elements? If not, please provide specific substantive suggestions for improvements to the VRFs or VSLs.

☐ Yes
☐ No
Comments:

Project 2008-12 - Coordinate Interchange Standards

Mapping Document

Project Purpose

The purpose of Project 2008-12 is to revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange. The drafting team also addressed the Interchange Subcommittee concerns related to the dynamic Transfers and Pseudo-ties and addressed previously identified stakeholder comments and applicable directives from Order 693. These issues and directives include defining communications on reloading interchange transactions due to different operational conditions and to bringing the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for: **R1.1.** All Dynamic Schedules at the expected average MW profile for each hour. Independent Expert Review recommendation: Retain Requirement.	Revised and Moved into INT-004-3	**INT-004-3:** R1. Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		method. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations] CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.
R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority: **R2.1.** If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator. **R2.2.** For each bilateral Inadvertent Interchange payback. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Retired	The CI SDT believes that this requirement is no longer necessary for reliability. Since the proposed INT-009-2 R1 makes it clear that the Net Scheduled Interchange term in the control equation can only include Confirmed Interchange as agreed to between Balancing Authorities, this by definition requires that an Arranged Interchange be created in order to implement the schedules listed in R2.1 and R2.2. From a reliability perspective, it is unimportant who creates these Arranged interchanges – only that they be created and confirmed prior to being entered into the control equation. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. **R1.1.** The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including: **R1.1.1.** Interchange Schedule start and end time. **R1.1.2.** Energy profile. **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. Independent Expert Review recommendation: Retain Requirement.	Revised and Moved into INT-009-2	**INT-009-2:** R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any interchange as directed by a Reliability Coordinator per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign to that of the Adjacent Balancing Authority. R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process).

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		[Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] R3. Each Balancing Authority in whose area the HVDC tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie if applicable. [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations, Operations Planning] CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Retired	The CI SDT believes that at a minimum, this requirement does not belong in the "Dynamic Schedules" standard. However, for several reasons, the CI SDT further believes that this specific requirement is no longer required: • It mandates a practice (releasing of E-Tag limits) that is process related. • The practice is already addressed in related NAESB standards (WEQ-004 Appendix B - E-Tag Actions). • Use of a limit (and the associated release of that limit) is only one particular way to address curtailments. Other ways exist that could be used in lieu of this approach. The reliability standard should not mandate a single approach when others may suffice. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.
R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and	Revised	**INT-004-2** **R2.** Each Load-Serving Entity that submitted a Request For Interchange in accordance with Requirement

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
future hours when any one of the following occurs: **R2.1.** The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +10%. **R2.2.** The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +25 megawatt-hours. **R2.3.** A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		R1, shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same Day Operations, Real Time Operations] 2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist. 2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist. 2.3. The Load-Serving Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have the RFI updated for a Dynamic Schedule or Pseudo-Tie that is significantly different than the original schedule. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis.

Standard: INT-005-3, Interchange Authority Distributes Arranged Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange. **R1.1.** When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Retired	The CISDT is proposing retirement of this requirement. The entities to receive the transaction are included today in the eTag specification, Section 3.6.1.1.1. The timing requirement for the distribution of tags is removed from this standard, as they are currently included and expected to remain in the NAESB documentation. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange. **R1.1.** Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to: **R1.1.1.** Energy profile (ability to support the magnitude of the Interchange). **R1.1.2.** Ramp (ability of generation maneuverability to accommodate). **R1.1.3.** Scheduling path (proper connectivity of Adjacent Balancing Authorities). **R1.2.** Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the	Revised	R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange. 1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the scheduling path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid. R2. Each Transmission Service Provider shall approve

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid. CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that this distribution requirement may currently drive how software performs this function. However, if that software were not present, this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		interchange to occur.

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following: **R1.1.** Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate). **R1.2.** All reliability entities involved in the Arranged Interchange are currently in the NERC registry. **R1.3.** The following are defined: **R1.3.1.** Generation source and load sink. **R1.3.2.** Megawatt profile. **R1.3.3.** Ramp start and stop times. **R1.3.4.** Interchange duration. **R1.4.** Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.	Retired, Revisions made to defined term used in various INT standards to clarify reliability objective	R1.1, R1.2 and R1.3 ensure the data submitted on the interchange is valid. This activity occurs in software validation and is not appropriate for a reliability standard; these items are included in the Technical Basis and Guidelines section of INT-006. Interchange that does not meet these criteria would not be an Arranged Interchange. R1.4. is addressed in the proposed revision to the definition of Confirmed Interchange: *The state where no party has denied and all required parties have approved the Arranged Interchange.* Requirement R4 also specifies conditions under which the BA shall not transition to Confirmed Interchange: R4. Each Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange under any of the following conditions: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 4.1. It is a Reliability Adjustment Arranged

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition. 4.2. It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition. 4.3. It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-008-3, Interchange Authority Distributes Status		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange. **R1.1.** For Confirmed Interchange, the Interchange Authority shall also communicate: **R1.1.1.** Start and stop times, ramps, and megawatt profile to Balancing Authorities. **R1.1.2.** Necessary Interchange information to NERC-identified reliability analysis services. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised and moved into INT-006-4	**INT-006-4:** R5. Each Sink Balancing Authority shall distribute all notifications of whether an Arranged Interchange was transitioned to Confirmed Interchange to the following entities, and notifications of on-time Confirmed Interchange shall be distributed such that they are delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 5.1. The Source Balancing Authority, 5.2. Each Intermediate Balancing Authority, 5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange, 5.4. Each Transmission Service Provider included in the Arranged Interchange, and 5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

Standard: INT-008-3, Interchange Authority Distributes Status		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that this distribution requirement may currently drive how software performs this function. However, if that software were not present, this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the interchange to occur.

Standard: INT-009-1, Implementation of Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Combined with INT-003-3, Requirement R1	**INT-009-2** **R1.** Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any interchange as directed by a Reliability Coordinator per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign to that of the Adjacent Balancing Authority. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs that a separate requirement is not necessary. This requirement was combined with INT-003-3, Requirement R1.

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised	**INT-010-2:** **R1.** The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R2. For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised	**INT-010-2:** **R2.** Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting that modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis
R3. For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent	Revised	**INT-010-2:**

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		**R3.** Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard	Modifications to Coordinate Interchange Standards for Applicability and General Upgrade
Request Date	May 27, 2008
Modified Date	December 1, 2008

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Interchange Subcommittee	☐	New Standard
Primary Contact Don Lacen, IS Chair	☒	Revision to existing Standards INT-001-2 — Interchange Transaction Tagging INT-003-2 — Interchange Transaction Implementation INT-004-1 — Interchange Transaction Modifications INT-005-2 — Interchange Authority Distributes Arranged Interchange INT-006-2 — Response to Interchange Authority INT-007-1 — Interchange Confirmation INT-008-2 — Interchange Authority Distributes Status INT-009-1 — Implementation of Interchange INT-010-1 — Interchange Coordination Exemptions
Telephone 505-241-2032 Fax 505-241-2582	☐	Withdrawal of existing Standard
E-maildon.lacen@pnm.com	☐	Urgent Action

Purpose **(Describe the proposed standard action: Nomination of a proposed standard, revision to a standard, or withdrawal of a standard and describe what the standard action will achieve.)** Revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange; to address the Interchange Subcommittee concerns related to the Dynamic Transfers and Pseudo-ties; to address previously identified stakeholder comments

and applicable directives from Order 693; to define communications on reloading interchange transactions due to different operational conditions; and to bring the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

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.)

There is confusion regarding the Interchange Authority "function". The need for improved clarity became apparent when entities were recently asked to register in the Compliance Registry as "Interchange Authorities" and entities had difficulty determining which entities were performing the Interchange Authority tasks identified in the set of Coordinate Interchange standards. The Interchange Authority activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities.

The Coordinate Interchange standards dealing with the Interchange Authority and the current Functional Model representations of the Interchange Authority do not reflect technological advances made since the Functional Model working group originally defined the Interchange authority and advances made since the Coordinate Interchange standards were written.

There are different interpretations surrounding the requirements associated with Dynamic Transfers and Pseudo-ties. Adding definitions for the terms used to reference Dynamic Transfers and Pseudo-ties (e.g., Dynamic Schedule, Dynamic Transfer, Pseudo-tie, Dynamic Schedule Curtailment) will add clarity to these requirements.

Additional requirements may be needed to address the principles outlined in the Interchange Subcommittee's Principles and Definitions Supporting Dynamic Transfers and Pseudo-ties. (Attachment 2)

Review the current NERC Glossary of Terms related to interchange to determine if any revisions or new definitions are necessary as a result of the Interchange standards development.

The work in this project should be addressed in at least two phases with a ballot conducted at the end of each phase. The first phase is needed as soon as possible and should focus on the revisions needed to ensure that each requirement is assigned to a user, owner or operator of the bulk power system. All other proposed revisions should be addressed in the second or subsequent phase(s) of the project.

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

The modifications in the set of Coordinate Interchange Standards should address the following:

- Determine if the activities in the Coordinate Interchange standards correctly identify the responsible entity.
- Consider requiring each Sink Balancing Authority or its designee to be responsible for providing the Interchange Authority functions using an interchange transaction tool process as defined in the latest approved version of the e-Tag

Specifications.

– The existing requirements are tool-neutral. Consider adding specific references to the e-Tagging process, applications, and tools in the requirements

– Consider adding a requirement to have backup capability for use when the interchange transaction tool fails.

– Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to follow.

– Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factor drafting team. (See Attachment 1)

– Determine if there is industry-wide support for the Interchange Subcommittee's Principles and definition supporting dynamic transfers and pseudo-ties, and if there is support, modify the requirements and add definitions accordingly.

– If there are no tasks assigned to the Interchange Authority function, then make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity.

Make other changes to the standards to bring them into conformance with the latest version of the Reliability Standards Development Procedure, Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

The work in this project should be done in two or more phases, with the first phase focused solely on clarifying the applicability of each requirement in the existing set of standards. All other revisions should take place in a second or subsequent phase(s).

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Revise the following set of Coordinate Interchange Standards so that the responsibility for each of the requirements is clearly assigned to an owner, operator or user of the bulk power system, and not to a tool.

INT-001-2 — Interchange Transaction Tagging

INT-003-2 — Interchange Transaction Implementation

INT-004-1 — Interchange Transaction Modifications

INT-005-2 — Interchange Authority Distributes Arranged Interchange

INT-006-2 — Response to Interchange Authority

INT-007-1 — Interchange Confirmation

INT-008-2 — Interchange Authority Distributes Status

INT-009-1 — Implementation of Interchange

INT-010-1 — Interchange Coordination Exemptions

Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to follow.

Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factor drafting team. (See Attachment 1)

Address the principles and definitions proposed by the Interchange Subcommittee in support of dynamic transfers and pseudo-ties. (See Attachment 2)

Make other changes to the standards to bring them into conformance with the latest version of the Reliability Standards Development Procedure, Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

If there are no tasks assigned to the Interchange Authority function, then make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity.
The work in this project should be addressed in at least two phases with a ballot conducted at the end of each phase. The first phase is needed as soon as possible and should focus on the revisions needed to ensure that each requirement is assigned to a user, owner or operator of the bulk power system. All other proposed revisions should be addressed in the second or later phases of the project.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	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 a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	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.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	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
CIP-002-1 through CIP-009-1	If the industry determines that the IA Function is not an "owner, operator or user" of the BES, then the applicability section of these standards should be modified to remove the IA as a responsible entity.

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1

(Issues originally intended for Project 2009-03 – Interchange Information)

INT-001-2 Interchange Information

Directives from FERC Order 693

- Include a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and “non-Order No. 888” transfers.
- Consider Santa Clara’s comments about the applicability of the LSE in the standard as part of the standards development process.

V0 Industry Comments

- R1 - Too stringent
- R1 – Who tags dynamic schedules?
- Load PSE responsibility is new restriction
- Clarify tagging of reserves
- R2.2 – 60 minute time frame questioned
- Question on generation scheduling
- Onerous to BA’s
- More commercial problem than reliability
- Lack of compliance

VRF Comments

- R1, 1.1, 2, 2.1, 2.2 – commercial and administrative

INT-003-2 Interchange Transaction Implementation

Unresolved Directives from FERC Order 693 – none

VRF Comments

- R1, 1.1, 1.1.2, 1.2 – commercial and administrative

INT-004-1 Dynamic Interchange Transaction Modifications

Unresolved Directives from FERC Order 693 – none

V0 Industry Comments

- Replace TSP with TOP
- Need to address tag curtailment
- Suggested non-compliance levels
- Non-compliance based on %
- Use WECC criteria

VRF Comments

- R2, 2.2, 2.3 – commercial and administrative

INT-005-2 Interchange Authority Distributes Arranged Interchange

Unresolved Directives from FERC Order 693 – none

VRF Comment

- R5 – administrative

INT-006-2 Response to Interchange Authority

Directives from FERC Order 693

- Include reliability coordinators and transmission operators as applicable entities.
- Require reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities' necessary transaction modifications before implementation.
- Consider the suggestions made by EEI and TVA and address questions raised by Entergy and Northern Indiana as part of the standard development process.

INT-007-1 Interchange Confirmation

Unresolved Directives from FERC Order 693 – none

VRF Comment

- R1, 1.1, 1.3, 1.3.1, 1.3.2, 1.3.3, 1.3.4, 1.4 – administrative

INT-008-2 Interchange Authority Distributes Status

Directives from FERC Order 693

- Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

VRF Comments

- R1.1.1 & 1.1.2 – commercial and administrative

INT-009-1 Implementation of Interchange

Directives from FERC Order 693

- Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

INT-010-1 Interchange Coordination Exemptions

Directives from FERC Order 693

- Consider Northern Indiana's and ISO-NE's suggestions in the standards development process.

VRF Comments

- R1 & 3 – administrative

Attachment 2 – Interchange Subcommittee's Principles and Definitions for Dynamic Schedules and Pseudo-ties

Dynamic Schedules

A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between balancing areas. A dynamic schedule must not change a balancing area's jurisdiction; that is, the native balancing area continues to exercise operational jurisdiction over, and provides basic balancing area services to, the dynamically scheduled resources.

All dynamic schedules used to assign the control of generation, loads, or resources from one balancing area to another must meet the following requirements:

1. Telemetry

1.1. Appropriate telemetry for a dynamic schedule must be in place and incorporated by all affected balancing areas. Standards requirements associated with this should address appropriateness issues related to accuracy, sampling rate, etc. which would impact reliability. For example, the relationship of BAL-005-1 R10 and BAL-005-1, R16 should be confirmed.

2. Transmission Service

2.1. Prior to implementation of the dynamic schedule of load or generation, it is the obligation of each involved balancing area to ensure that the dynamic schedule is implemented such that the tariff requirements of the applicable transmission provider(s) are met, including applicable ancillary services and provision of losses.

2.2. If transmission service between the source and sink balancing areas is curtailed then the allowable range of the magnitude of the schedules between them, including dynamic schedules, must be curtailed accordingly. Since dynamic schedules are implemented in ACE via telemetry, curtailment of e-Tags associated with dynamic schedules must be complemented with appropriate adjustments to the telemetered values used in ACE to make the curtailment be physically implemented via ACE control action.

3. System Modeling

3.1. Each balancing area must ensure that the dynamic transfer of load or generation through a dynamic schedule is coordinated with the Reliability Coordinator(s) with responsibility over the native, attaining, and contract intermediary balancing areas so that the dynamic schedule can be properly implemented in the system modeling of the affected generation or load, and necessary data provision requirements are met. Coordination must include tagging of the resultant scheduled interchange for use by other transmission providers and balancing areas for system security analysis and calculation of ATC.

3.2. When a dynamic schedule is used to serve load within another balancing area, the balancing area where the load is electrically connected (native balancing area) must include that load in its balancing area load forecast and any subsequent reporting as needed. This is necessary because the system models must adequately capture the projected demand on the system (load forecast), and the projected supply (provided by the electronic tagging system).

4. Dynamic Schedule Coordination and Scheduling

4.1. Although implemented in the ACE via telemetry, implementation of a dynamic schedule for NERC-identified reliability analysis services must be through the use of an interchange transaction between balancing areas. As such, all dynamic schedules must be tagged and implemented in accordance with NERC Standards.

4.2. Energy exchanged between the source, sink, and intermediary balancing areas as a dynamic schedule is the metered or calculated (obtained by the integration of the dynamic schedule signal over the operating hour) energy for the loads and/or resources for the hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.
4.3. The native balancing area must ensure that agreements are in place defining the responsibility for providing applicable ancillary/interconnected operations services.
4.4. The drafting team should consider reliability impacts and draft appropriate standards related to how dynamic schedules are modeled from various perspectives such as level of detail (i.e. degree to which composite representation is allowed such as each generator having dynamic schedule or allowing a composite plant dynamic schedule) and use of block schedules to serve part of a dynamic schedule. In the latter case, although a single telemetered value may be used in the ACE for a load, it can be represented in the e-Tagging by a combination of one or more block schedules for part of the load and a dynamic schedule for the remainder to represent the dynamic nature of a load.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the dynamic schedule on a plan for how the balancing areas will operate during a loss of the dynamic schedule telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.
5.2. The native balancing area, attaining balancing area and intermediary balancing areas shall agree before implementation of the dynamic schedule upon a plan for how the load will be served during abnormal system conditions including periods of time when the transfer path between them is unavailable. The native balancing area, attaining control area and intermediary balancing areas shall also agree before implementation of the dynamic schedule as to how the generation serving the dynamic schedule will respond during abnormal system conditions, including periods of time when the transfer path between them is unavailable.

Pseudo-Ties
Pseudo-ties are often employed to assign generators, loads, or both from the balancing area to which they are physically connected into a balancing area that has effective operational control of them. Thus, pseudo-ties provide for change of balancing area jurisdiction from the native to the attaining balancing area and at the same time make the attaining balancing area provider of balancing area services. This methodology is also referred to as “AGC Interchange” or “Non-Contiguous Pool Tie.” In practice, pseudo-ties may be implemented based upon metered or calculated values. All balancing areas involved account for the power exchange and associated transmission losses as actual interchange between the balancing areas, both in their ACE equations and throughout all of their energy accounting processes.

All pseudo-ties used to assign generation, loads, or resources from the native balancing area to the attaining balancing area must meet the following requirements:
1. Telemetry
1.1. Appropriate telemetry must be in place and incorporated by all affected balancing areas.

2. Transmission Service
2.1. Prior to implementation of the dynamic transfer of load or generation by pseudo-tie, each involved balancing area shall ensure that the pseudo-tie is implemented such that the

tariff requirements of the applicable transmission provider(s), including applicable ancillary services and provision of losses, are met.
2.2. If transmission service between the native and attaining balancing areas is curtailed, then the allowable range of the magnitude of the pseudo-ties between them must be limited accordingly to these constraints. Since pseudo-ties are implemented in ACE via telemetry, appropriate adjustments must be made to the telemetered values used in ACE to make a curtailment be physically implemented via ACE control action.
2.3. Pseudo-ties must be implemented on firm transmission and are subject to curtailment on a pro rata basis with other firm transactions.

3. System Modeling
3.1. The assignment of load or generation into the control response of another balancing area must be appropriately captured in the IDC and security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators. It is the obligation of each balancing area to ensure that the dynamic transfer of load or generation by pseudo-ties is coordinated with the Reliability Coordinator(s) that have responsibility over the native, attaining, and contract intermediary balancing areas so that the pseudo-tie can be properly implemented in the system modeling of the generation or load affected, and necessary data provision requirements are met.
3.2. The attaining balancing area dynamically transferring load into its effective boundaries through a pseudo-tie shall ensure that load forecasts and subsequent balancing area reporting reflect the load incorporated within its balancing area boundaries.
3.3. If the reliability impact of the pseudo-tie cannot be accurately captured in the IDC and the security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators, the parties must implement the dynamic transfer either through use of a dynamic schedule, or through a combined implementation of pseudo-tie and dynamic schedule where the load or generation within the native balancing area is separately modeled in the IDC.
3.4. The drafting team should consider clarifying how pseudo-tie can be used in reliability analysis activities. For example, since they are not physical ties, should they be omitted from being used as part of a defined flowgate and in physical interface calculations yet be included in inadvertent calculations

4. Pseudo-Ties Coordination and Scheduling
4.1. Subsequent to moving load or resources into an attaining balancing area through pseudo-ties, all interchange transactions or other energy transfers to the loads or from the resources must be coordinated by the attaining balancing area.
4.2. The attaining balancing area assumes responsibility for balancing area services required by the assigned loads and/or resources. The attaining balancing area assumes all regulation, contingency reserves, and other balancing area responsibilities for the loads and/or resources in question.
4.3. Energy exchanged between the native and attaining balancing areas by the pseudo-tie method is accounted for by the associated revenue meter reading for the operating hour (if such meter exists at the dynamically assigned resource or load) or energy calculated by integrating the associated telemetered real-time signal over the operating hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie on a plan for how the balancing areas will operate during a loss of the pseudo-tie telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good

value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

5.2. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie upon a plan for how the load will be served during abnormal system conditions including periods of time when the interconnection between them is lost. The native balancing area, attaining balancing area, and intermediary balancing areas shall also agree before implementation of the pseudo-tie how the entities will respond during abnormal system conditions, including periods of time when the connection between them is unavailable.

Dynamic Transfer Reference Document

The Drafting Team should take the existing Dynamic Transfer Reference Document, update it as necessary to reflect Functional Model terms and any changes necessary as a result of new requirements from the standards drafting resulting from this SAR and submit it for ballot as a formal reference document linked to those standards. This will provide the industry with a formal, official document to provide guidance on the implementation of dynamic transfers covered in the standards.

The Interchange Subcommittee recommends moving INT-001 standard requirement R.1. to a more appropriate INT standard such as INT-001 or INT-003.

Note: In addition to the above requirements, the NERC Glossary of Terms may need to be amended to include the following new or revised definitions:

ATTAINING BALANCING AREA — A balancing area bringing generation or load into its effective control boundaries through dynamic transfer from the Native Balancing area.

DYNAMIC SCHEDULE — A telemetered reading, or value that is updated in real-time and used as a schedule in the AGC/ACE equation of the affected balancing areas and the integration of which is treated as a schedule for interchange accounting purposes. To the extent that no associated energy metering equipment exists, the integration of the telemetered real time signal is used as a scheduled MWh value for interchange accounting purposes.

DYNAMIC TRANSFER — The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to implement a dynamic schedule or pseudo-tie.

INTEGRATION in the context of dynamic schedules and pseudo-ties means the value could be mathematically calculated or determined mechanically with a metering device.

INTERCONNECTED OPERATIONS SERVICE (IOS) — A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected bulk electric systems.

NATIVE BALANCING AREA — A balancing area from which a portion of its physically interconnected generation and/or load is assigned from its effective control boundaries through dynamic transfer to the attaining balancing area.

PSEUDO-TIE — A telemetered reading, or value that is updated in real time, representative of generation or load assigned dynamically between balancing areas and used as a tie line flow in the affected balancing areas' AGC/ACE equation, but for which no physical balancing area tie actually exists. To the extent that no associated energy metering equipment exists,

the integration of the telemetered real time signal is used as a metered MWh value for interchange accounting purposes.

Project 2008-12: Coordinate Interchange Standards

VRF and VSL Justifications for INT-004-3

VRF and VSL Justifications – INT-004-3, R1	
Proposed VRF	Lower
NERC VRF Discussion	Dynamic Schedules or Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring Arranged Interchanges is submitted, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Load-Serving Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method,

VRF and VSL Justifications – INT-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to submit a Request for Interchange.

VRF and VSL Justifications – INT-004-3, R2	
Proposed VRF	Lower
NERC VRF Discussion	Dynamic Schedules or Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-004-2, R2, which deals with updating tagging information and is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1-2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-004-3, R2	
Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to ensure the Confirmed Interchange or Pseudo-Tie was updated for the next available scheduling hour or future hours.

VRF and VSL Justifications – INT-004-3, R3	
Proposed VRF	Lower
NERC VRF Discussion	Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring Arranged Interchanges is submitted, is assigned a Lower VRF. Also, INT-004-3, R1, which deals with submittal of RFI, is also assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority did not register a Pseudo-Tie for which data was used in its ACE equation in the NAESB Electric Industry Registry.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of	This guideline is not applicable because this is a new requirement.

VRF and VSL Justifications – INT-004-3, R3	
Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to register a Pseudo-Tie in the NASEB Electric Industry Registry.

Project 2008-12: Coordinate Interchange Standards

VRF and VSL Justifications for INT-006-4

VRF and VSL Justifications – INT-006-4, R1	
Proposed VRF	Lower
NERC VRF Discussion	Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-006-3, R1, which deals with responding to on-time RFI, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny its transition to Confirmed Interchange prior to the expiration of the time period defined in Attachment 1, Column B. OR

VRF and VSL Justifications – INT-006-4, R1	
	The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange. OR The scheduling path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned “Severe.” Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-006-4, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to take action on an on-time Arranged Interchange or an emergency Arranged Interchange, or for failing to deny an Arranged Interchange under certain circumstances.

VRF and VSL Justifications – INT-006-4, R2	
Proposed VRF	Lower
NERC VRF Discussion	Transmission Service Providers must take action on a received Arranged Interchange within a certain time frame. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-006-3, R1, which deals with responding to on-time RFI, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A

VRF and VSL Justifications – INT-006-4, R2	
Proposed Severe VSL	The Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny its transition to Confirmed Interchange prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned “Severe.” Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-006-4, R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to take action on an on-time Arranged Interchange or an emergency Arranged Interchange, or for failing to deny an Arranged Interchange or curtail Confirmed Interchange under certain circumstances.

VRF and VSL Justifications – INT-006-4, R3	
Proposed VRF	Lower
NERC VRF Discussion	Source or Sink Balancing Authorities receiving a Reliability Adjustment Arranged Interchange need to approve or deny it prior to the expiration of the reliability assessment period defined in the timing requirements. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-006-3, R1, which deals with approving or denying Arranged Interchange is submitted, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – INT-006-4, R3	
Proposed High VSL	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.
Proposed Severe VSL	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-006-4, R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to act on a Reliability Adjustment Arranged Interchange within a certain time frame, or for failing to communicate a denial to the Reliability Coordinator within 10 minutes of the denial.

VRF and VSL Justifications – INT-006-4, R4	
Proposed VRF	Lower
NERC VRF Discussion	Balancing Authorities should not transition Arranged Interchange to Confirmed Interchange under certain conditions. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-007-13, R1, which deals with ensuring Arranged Interchanges is valid before transitioning to Confirmed Interchange, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – INT-006-4, R4	
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning an Arranged Interchange to Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of transitioning an Arranged Interchange to Confirmed Interchange under certain circumstances under which an Interchange should not be transitioned.

VRF and VSL Justifications – INT-006-4, R5	
Proposed VRF	Lower
NERC VRF Discussion	Distributing information regarding whether an Arranged Interchange was transitioned to Confirmed Interchange is necessary to ensure that everyone has the same information regarding the transactions. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-008-3, R1, which deals with distributing information regarding whether an Arranged Interchange was transitioned to Confirmed Interchange, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	The Sink Balancing Authority did not distribute notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to all of the entities listed in Requirement R5 Parts 5.1-5.5.
Proposed Severe VSL	The Sink Balancing Authority did not notify the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.

VRF and VSL Justifications – INT-006-4, R5	
	OR The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify the entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to distribute notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to specific entities.

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VRF and VSL Justifications for INT-009-2

VRF and VSL Justifications – INT-009-2, R1	
Proposed VRF	Medium
NERC VRF Discussion	Agreement between Balancing Authorities regarding the magnitude and direction of Composite Confirmed Interchange is necessary to ensure that each balancing Authority is controlling their generation for the proper amount of Interchange. If the values are not agreed to, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, excluding Dynamic Schedules and including any interchange as directed by a Reliability Coordinator per INT-010-2 not yet captured in the Composite Confirmed Interchange, for that

VRF and VSL Justifications – INT-009-2, R1	
	hour.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned “Severe.” Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, excluding Dynamic Schedules and including any interchange as directed by a Reliability Coordinator per INT-010-2 not yet captured in the Composite Confirmed Interchange, for that hour.

VRF and VSL Justifications – INT-009-2, R2	
Proposed VRF	Medium
NERC VRF Discussion	Agreement between Balancing Authorities regarding the source to be used for a Pseudo-Tie is necessary to ensure that each balancing Authority is controlling their generation for the proper amount of Interchange associated with the Pseudo-Tie. If the values are not agreed to, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process).
FERC VSL G1 Violation Severity Level Assignments Should Not	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-009-2, R2	
Have the Unintended Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process).

VRF and VSL Justifications – INT-009-2, R3	
Proposed VRF	Medium
NERC VRF Discussion	Coordination of Interchange across HVDC is necessary to ensure that the Facility is operated within its limits and that each Balancing Authority is controlling to a correct Interchange value. If the interchange is not appropriately accounted for, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-009-2, R3	
the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie..

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VRF and VSL Justifications for INT-010-2

VRF and VSL Justifications – INT-010-2, R1	
Proposed VRF	Lower
NERC VRF Discussion	After the fact submittal of a Request For Interchange (RFI) will not impact transmission congestion but may impact the ability to adequately assess transmission conditions for future hours. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-010-1, R1, which deals with submitting Arranged Interchange after the fact, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss.
Proposed Moderate VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss.

VRF and VSL Justifications – INT-010-2, R1	
Proposed High VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss.
Proposed Severe VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement did not ensure that a RFI was submitted following the resource loss.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for this requirement mirror existing VSLs for this revised requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-010-2, R1	
Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to ensure that the Request for Interchange was submitted, or for an RFI that was submitted with a start time more than 60 minutes following the resource loss.

VRF and VSL Justifications – INT-010-2, R2	
Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures that modified RFI is submitted for any Interchange that was modified at the direction of a Reliability Coordinator. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-010-1, R2, which deals with submitting a modified Arrange Interchange, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.

VRF and VSL Justifications – INT-010-2, R2	
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting the modification was submitted within 60 minutes following the start of the modification.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	The VSL is assigned for a single instance of ensuring that a Reliability Adjustment Arranged Interchange reflecting the modification was submitted within 60 minutes following the start of the modification.

VRF and VSL Justifications – INT-010-2, R2	
on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – INT-010-2, R3	
Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures that modified RFI is submitted for any Interchange that was modified at the direction of a Reliability Coordinator. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-010-1, R3, which deals with submitting a modified Arrange Interchange, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority did not ensure that a RFI was submitted within 60 minutes following the start of the scheduled Interchange.

VRF and VSL Justifications – INT-010-2, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of not ensuring that a RFI was submitted within 60 minutes following the start of the scheduled Interchange.

VRF and VSL Justifications – INT-010-2, R4	
Proposed VRF	Medium
NERC VRF Discussion	Distribution of Reliability Adjustment Arranged Interchange can impact transmission congestion evaluation, and the distribution needs to be communicated and accounted for in congestion management processes. If the transfers were not appropriately accounted for, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority involved in a Pseudo-Tie or Dynamic Schedule failed to ensure that the MW value from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange was not exceeded in its ACE equation.
FERC VSL G1 Violation Severity Level	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-010-2, R4	
Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to ensure that the MW value from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange was not exceeded in its ACE equation..

Project 2008-12: Coordinate Interchange Standards

VRF and VSL Justifications for INT-011-1

VRF and VSL Justifications – INT-011-1, R1	
Proposed VRF	Lower
NERC VRF Discussion	Transfers within a Balancing Authority Area can potentially impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring that Arranged Interchange is submitted. This requirement is assigned a Lower VRF
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Load-Serving Entity used Point to Point Transmission Service for an intra-Balancing Authority Area transfer, and did not submit a Request for Interchange for an intra-Balancing Authority transfer that is not included in congestion management procedure(s) via an alternate method.

VRF and VSL Justifications – INT-011-1, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted or the transfer is not included in congestion management procedure(s) via an alternate method.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to submit a Request for Interchange or include the transfer in congestion management procedure(s) via an alternate method.

A. Introduction

1. **Title: Interchange Information**
2. **Number:** INT-001-3
3. **Purpose:**
   To ensure that Interchange information is submitted to the NERC-identified reliability analysis service.
4. **Applicability:**
   4.1. Purchase-Selling Entities.
   4.2. Balancing Authorities.
5. **Effective Date:** August 27, 2008 (U.**S.)**
   NERC Board Approval: October 9, 2007

B. Requirements

R1. The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:

R1.1. All Dynamic Schedules at the expected average MW profile for each hour.

R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:

R2.1. If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.

R2.2. For each bilateral Inadvertent Interchange payback.

C. Measures

M1. The Purchasing-Selling Entity that serves the load shall have and provide upon request evidence that could include but is not limited to, its 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 Arranged Interchange was submitted to the Interchange Authority for all Dynamic Schedules at the expected average MW profile for each hour as specified in Requirement 1.

M2. Each Sink 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 Arranged Interchange was submitted to the Interchange Authority as specified in Requirements 2.1 and 2.2.

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

The Purchasing-Selling Entity that serves load and Sink Balancing Authority shall each 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. Levels of Non-Compliance for Sink Balancing Authorities:

2.1. Level 1: One instance of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and R2.2.

2.2. Level 2: Two instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

2.3. Level 3: Three instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

2.4. Level 4: Four or more instances of not submitting Arranged Interchange to the Interchange Authority as specified in R2.1 and 2.2.

3. Levels of Non-Compliance for Purchasing-Selling Entities that Serve Load:

3.1. Level 1: One instance of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.2. Level 2: Two instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.3. Level 3: Three instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

3.4. Level 4: Four or more instances of not submitting Arranged Interchange to the Interchange Authority as specified in R1.

E. Regional Differences

1. MISO Energy Flow Information Waiver effective on 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	October 9, 2008	Adopted by Board of Trustees (Remove WECC Waiver)	Revised
3	July 21, 2008	Regulatory Approval	Revised

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	November 5, 2009	Added approved VRFs and VSLs to document. Removed MISO Scheduling Agent Waiver, and MISO Enhanced Scheduling Agent Waiver (Project 2009-18).	Revised
3	November 5, 2009	Approved by the Board of Trustees	
3	January 6, 2011	Approved by FERC	

A. Introduction

1. **Title:** **Dynamic Interchange Transaction Modifications**

2. **Number:** INT-004-2

3. **Purpose:** To ensure Dynamic Transfers are adequately tagged to be able to determine their reliability impacts.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Reliability Coordinators

   4.3. Transmission Operators

   4.4. Purchasing-Selling Entities

5. **Effective Date:** August 27, 2008 (U.**S.)**

   NERC Board Approval: October 9, 2007

B. Requirements

R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.

R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs:

R2.1. The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±10%.

R2.2. The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±25 megawatt-hours.

R2.3. A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.

C. Measures

M1. The Sink Balancing Authority shall provide evidence that the responsible Purchasing-Selling Entity revised a tag when the deviation exceeded the criteria in INT-004 Requirement 2.

D. Compliance

1. **Compliance Monitoring Process**
   Periodic tag audit as prescribed by NERC. For the requested time period, the Sink Balancing Authority shall provide the instances when Dynamic Schedule deviation

exceeded the criteria in INT-004 R2 and shall provide evidence that the responsible Purchasing-Selling Entity submitted a revised tag.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year without a violation from the time of the violation.

1.3. Data Retention

Three months.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Not specified.

2.2. Level 2: Not specified.

2.3. Level 3: Not specified.

2.4. Level 4: Not specified.

E. Regional Differences

1. None

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Board of Trustees Approval	Revised
2	October 9, 2007	Board of Trustees Approval (Removal of WECC Waiver)	Revised
2	July 21, 2008	FERC Approval	Revised

A. Introduction

1. **Title:** **Interchange Authority Distributes Arranged Interchange**

2. **Number:** INT-005-3

3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is distributed by an Interchange Authority such that Interchange information is available for reliability assessments.

4. **Applicability:**

   4.1. Interchange Authority.

5. **Effective Date:** July 1, 2010

B. Requirements

R1. Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange.

R1.1. When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall be able to provide evidence that it has distributed the Arranged Interchange information to all reliability entities involved in the Interchange within the applicable time frame.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

1.3. Data Retention

The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a specific complaint of failure to perform R1. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate the Interchange Authority's distribution of all Arranged Interchange information to all reliability entities involved in an Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Interchange Authority.

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate that the Interchange Authority distributed the Arranged Interchange information to all reliability entities involved in that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not distributing information to all involved reliability entities as described in R1.

2.2. Level 2: Two occurrences[1] of not distributing information to all involved reliability entities as described in R1.

2.3. Level 3: Three occurrences[1] of not distributing information to all involved reliability entities as described in R1.

2.4. Level 4: Four or more occurrences[1] of not distributing information to all involved reliability entities as described in R1 or no evidence provided.

E. Regional Differences

None

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised
3	April 8, 2010	Approved by FERC, Effective July 1, 2010	

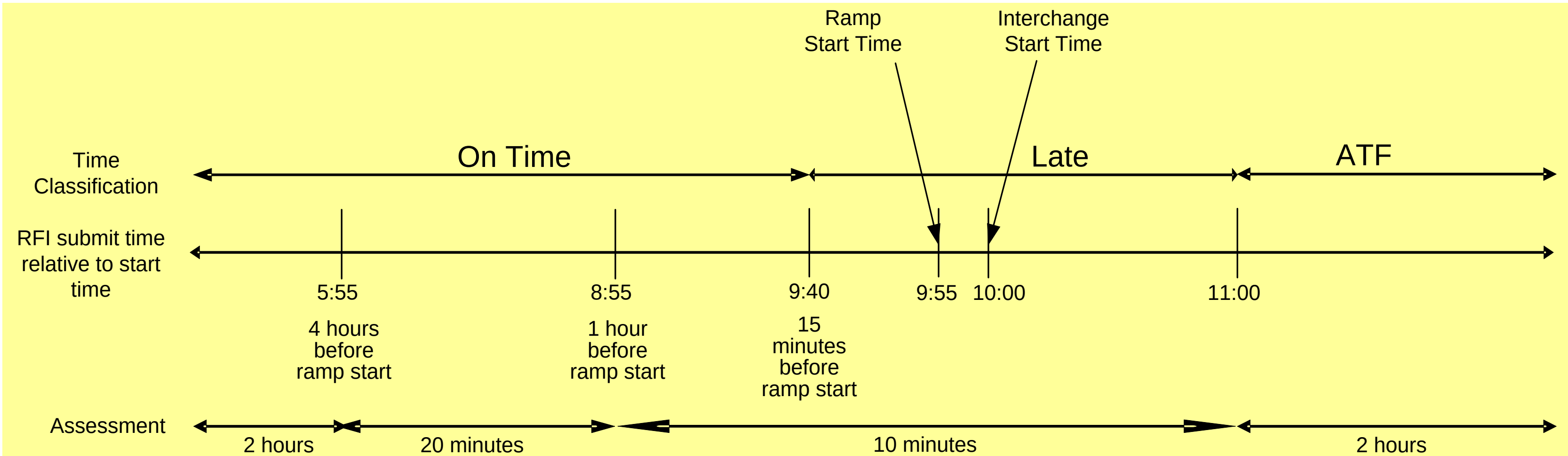
[1] This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange (RFI)[2] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the RFI start time	ATF	≤ 1 minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
<15 minutes prior to ramp start and ≤1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[2] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC

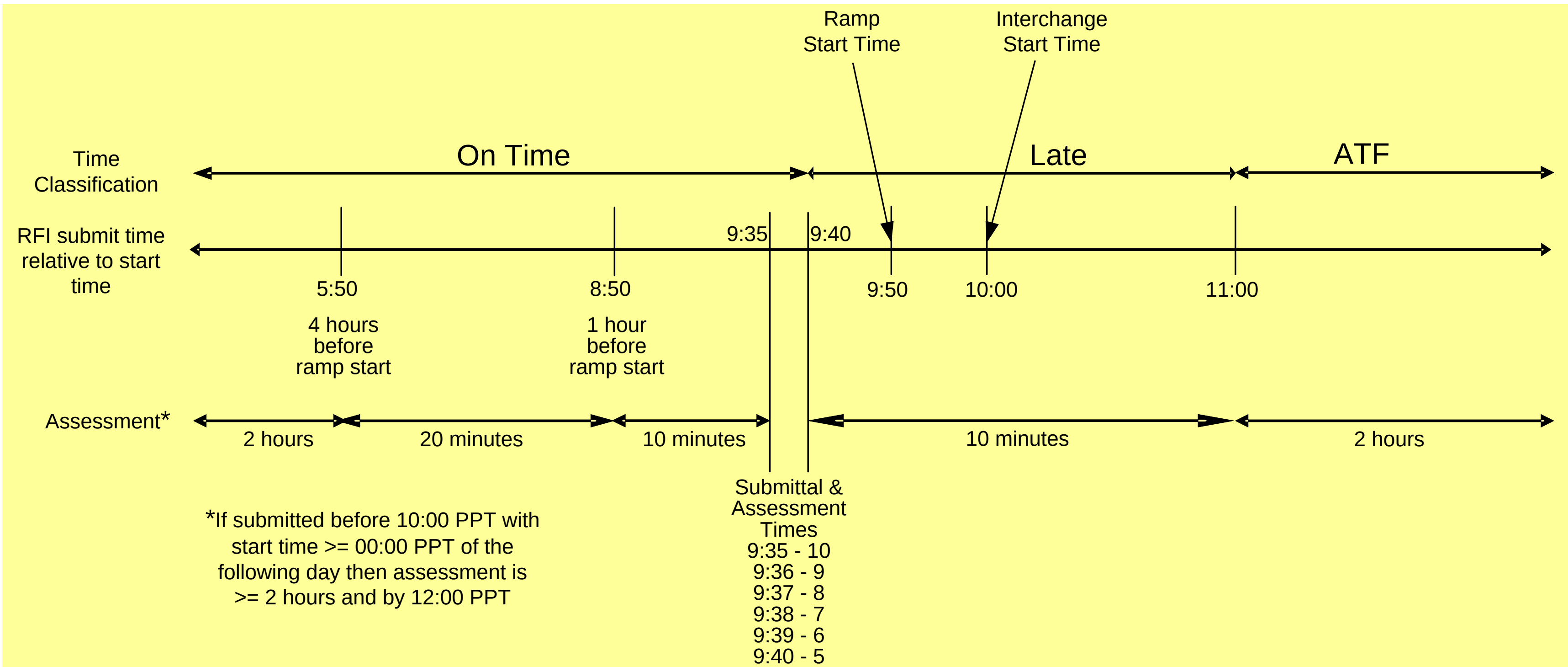


Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange (RFI)[3] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
10 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 6 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
12 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 7 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 8 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 9 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1hour and < 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	< 20 minutes from Arranged interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time	≤ 1minute from RFI submission	By 12:00 PPT of day the Arranged Interchange was received by the IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC



A. Introduction

1. **Title:** **Response to Interchange Authority**
2. **Number:** INT-006-3
3. **Purpose:** To ensure that each Arranged Interchange is checked for reliability before it is implemented.
4. **Applicability:**
   - **4.1.** Balancing Authority.
   - **4.2.** Transmission Service Provider.
5. **Effective Date:** July 1, 2010

B. Requirements

R1. Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.[1]

R1.1. Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:

R1.1.1. Energy profile (ability to support the magnitude of the Interchange).

R1.1.2. Ramp (ability of generation maneuverability to accommodate).

R1.1.3. Scheduling path (proper connectivity of Adjacent Balancing Authorities).

R1.2. Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated.

C. Measures

M1. The Balancing Authority and Transmission Service Provider shall each provide evidence that it responded, relative to transitioning an Arranged Interchange to a Confirmed Interchange, to each On–time Request for Interchange (RFI), and to each Emergency RFI or Reliability Adjustment RFI from an Interchange Authority within the reliability assessment period defined in the Timing Table, Column B. The Balancing Authority and Transmission Service Provider need not provide evidence that it responded to any other requests.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility
Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

[1] The Balancing Authority and Transmission Service Provider need not provide responses to any other requests.

1.3. Data Retention

The Balancing Authority and Transmission Service Provider shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

The Balancing Authority and Transmission Service Provider shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authority, and Transmission Service Provider shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records and agreements for the audit period which indicate a reliability entity identified in R1 responded to all instances of the Interchange Authority's communication under Reliability Standard INT-005 Requirement 1 concerning the pending transition of an Arranged Interchange to Confirmed Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority, or Transmission Service Provider.

1.4.6 For specific complaints, agreements and those data and system log records associated with the specific Interchange event contained in the complaint which indicates a reliability entity identified in R1 has responded to the Interchange Authority's communication under INT-005 R1 concerning the pending transition of Arranged Interchange to Confirmed Interchange for that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[2] of not responding to the Interchange Authority as described in R1.

2.2. Level 2: Two occurrences[1] of not responding to the Interchange Authority as described in R1.

2.3. Level 3: Three occurrences[1] of not responding to the Interchange Authority as described in R1.

[2] This does not include instances of not responding due to extenuating circumstances approved by the Compliance Monitor.

2.4. Level 4: Four or more occurrences[1] of not responding to the Interchange Authority as described in R1 or no evidence provided.

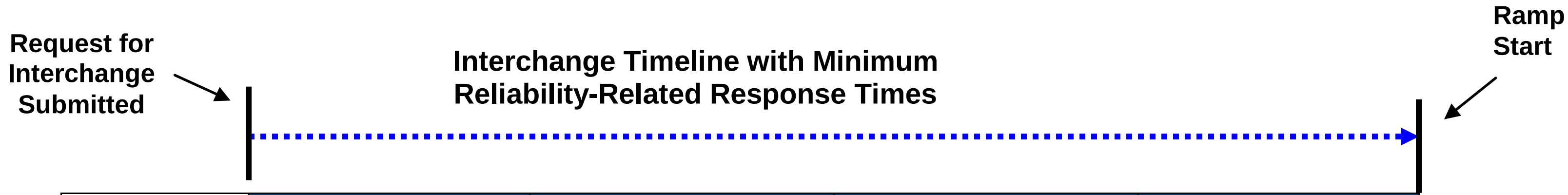
E. Regional Differences

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised
3	April 8, 2010	Approved by FERC, Effective July 1, 2010	

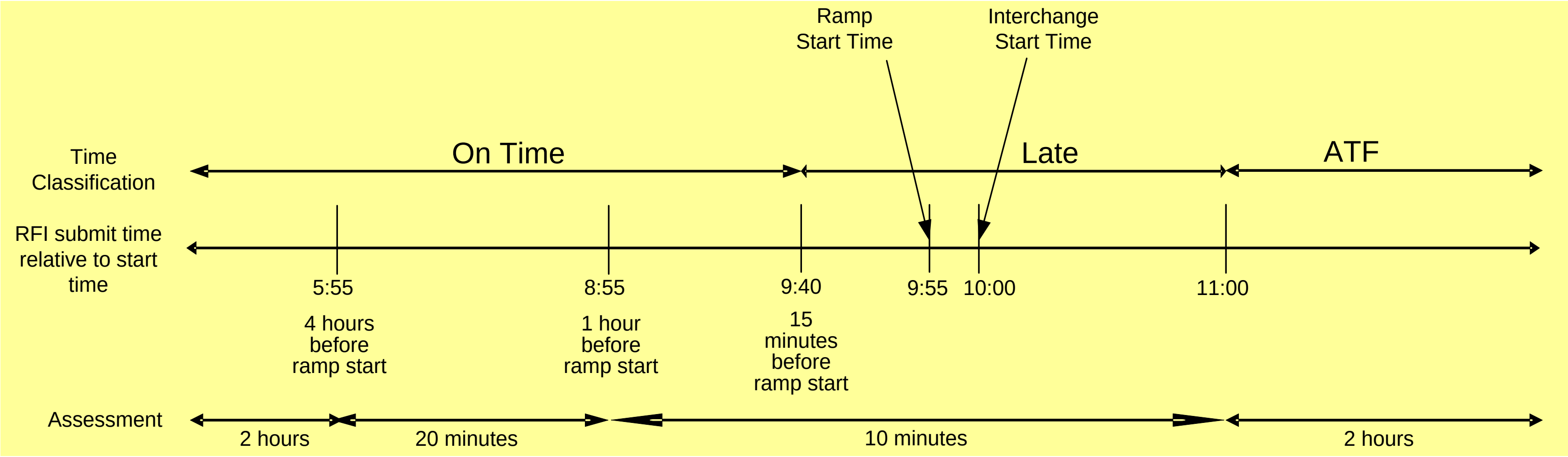
Timing Requirements for all Interconnections except WECC



		A	B	C	D
If Arranged Interchange (RFI)[3] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the RFI start time	ATF	≤ 1 minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
<15 minutes prior to ramp start and ≤1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC

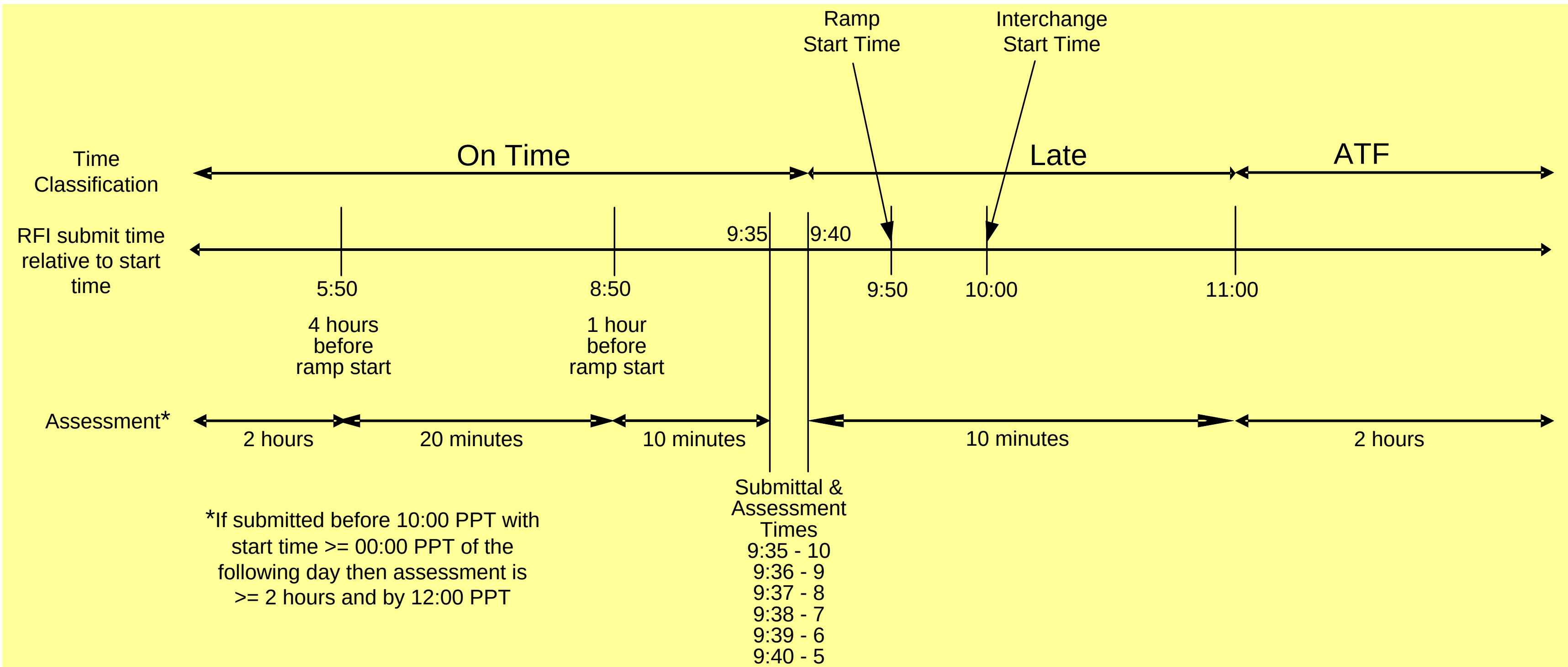


Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange (RFI)[4] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
10 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 6 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
12 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 7 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 8 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 9 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1hour and < 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	< 20 minutes from Arranged interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time	≤ 1minute from RFI submission	By 12:00 PPT of day the Arranged Interchange was received by the IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[4] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC



A. Introduction

1. **Title:** **Interchange Confirmation**

2. **Number:** **INT-007-1**

3. **Purpose:** To ensure that each Arranged Interchange is checked for reliability before it is implemented.

4. **Applicability**

   4.1. Interchange Authority.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following:

R1.1. Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).

R1.2. All reliability entities involved in the Arranged Interchange are currently in the NERC registry. (Retirement approved by NERC BOT pending applicable regulatory approval.)

R1.3. The following are defined:

R1.3.1. Generation source and load sink.

R1.3.2. Megawatt profile.

R1.3.3. Ramp start and stop times.

R1.3.4. Interchange duration.

R1.4. Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall show evidence that it has verified the Arranged Interchange information prior to the dissemination of the Confirmed Interchange.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.

   1.3. Data Retention

   The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate an Interchange Authority's verification that all Arranged Interchange was balanced and valid as defined in R1. The Compliance Monitor may request up to a three-month period of historical data ending with the date the request is received by the Interchange Authority.

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate an Interchange Authority's verification that an Arranged Interchange was balanced and valid as defined in R1 for that specific Interchange

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] where Interchange-related data was not verified as defined in R1.

2.2. Level 2: Two occurrences where Interchange-related data was not verified as defined in R1.

2.3. Level 3: Three occurrences where Interchange-related data was not verified as defined in R1.

2.4. Level 4: Four or more occurrences where Interchange-related data was not verified as defined in R1.

E. Regional Differences

None

[1] This does not include instances of not verifying due to extenuating circumstances approved by the Compliance Monitor.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Adopted by the NERC Board of Trustees	
1	March 16, 2007	FERC Approved	
1	February 7, 2013	R1.2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	

A. Introduction

1. **Title:** **Interchange Authority Distributes Status**

2. **Number:** INT-008-3

3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority.

4. **Applicability:**

   4.1. Interchange Authority.

5. **Effective Date:** July 1, 2010

B. Requirements

R1. Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange.

R1.1. For Confirmed Interchange, the Interchange Authority shall also communicate:

R1.1.1. Start and stop times, ramps, and megawatt profile to Balancing Authorities.

R1.1.2. Necessary Interchange information to NERC-identified reliability analysis services.

C. Measures

M1. For each Arranged Interchange, the Interchange Authority shall provide evidence that it has distributed the final status and Confirmed Interchange information specified in Requirement 1 to all Balancing Authorities, Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange within the time period defined in the Timing Table, Column C. If denied, the Interchange Authority shall tell all involved parties that approval has been denied.

M1.1 For each Arranged Interchange that includes a direct current tie, the Interchange Authority shall provide evidence that it has communicated the final status to the Balancing Authorities on both sides of the direct current tie, even if the Balancing Authorities are neither the Source nor Sink for the Interchange.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last non-compliance to R1.

   1.3. Data Retention

The Interchange Authority shall keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance will be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate the Interchange Authority's distribution of all Arranged Interchange final status and Confirmed Interchange information to all entities involved in an Interchange per R1. The Compliance Monitor may request up to a three-month period of historical data ending with the date the request is received by the Interchange Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicate that the Interchange Authority distributed the Arranged Interchange final status and Confirmed Interchange information to all entities involved in that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not distributing final status and information as described in R1.

2.2. Level 2: Two occurrences[1] of not distributing final status and information as described in R1.

2.3. Level 3: Three occurrences[1] of not distributing final status and information as described in R1.

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[1] This does not include instances of not distributing information due to extenuating circumstances approved by the Compliance Monitor.

2.4. Level 4: Four or more occurrences[1] of not distributing final status and information as described in R1 or no evidence provided.

E. **Regional Differences**

None.

Version History

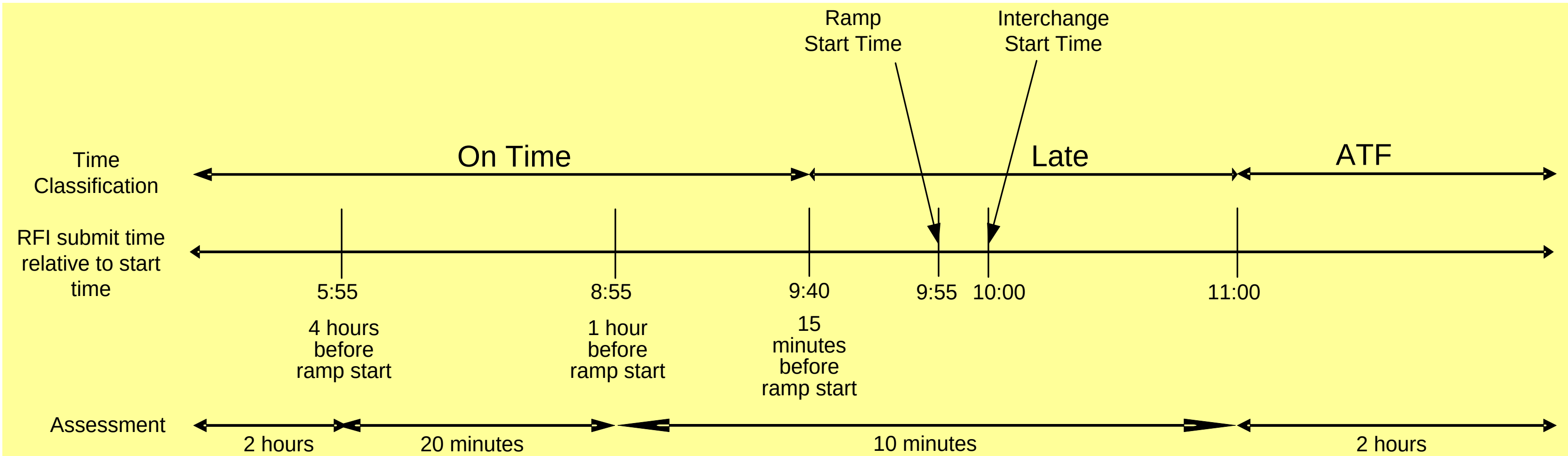
Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised
3	April 8, 2010	Approved by FERC, Effective July 1, 2010	

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange (RFI)[2] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the RFI start time	ATF	≤ 1 minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
<15 minutes prior to ramp start and ≤1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[2] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC

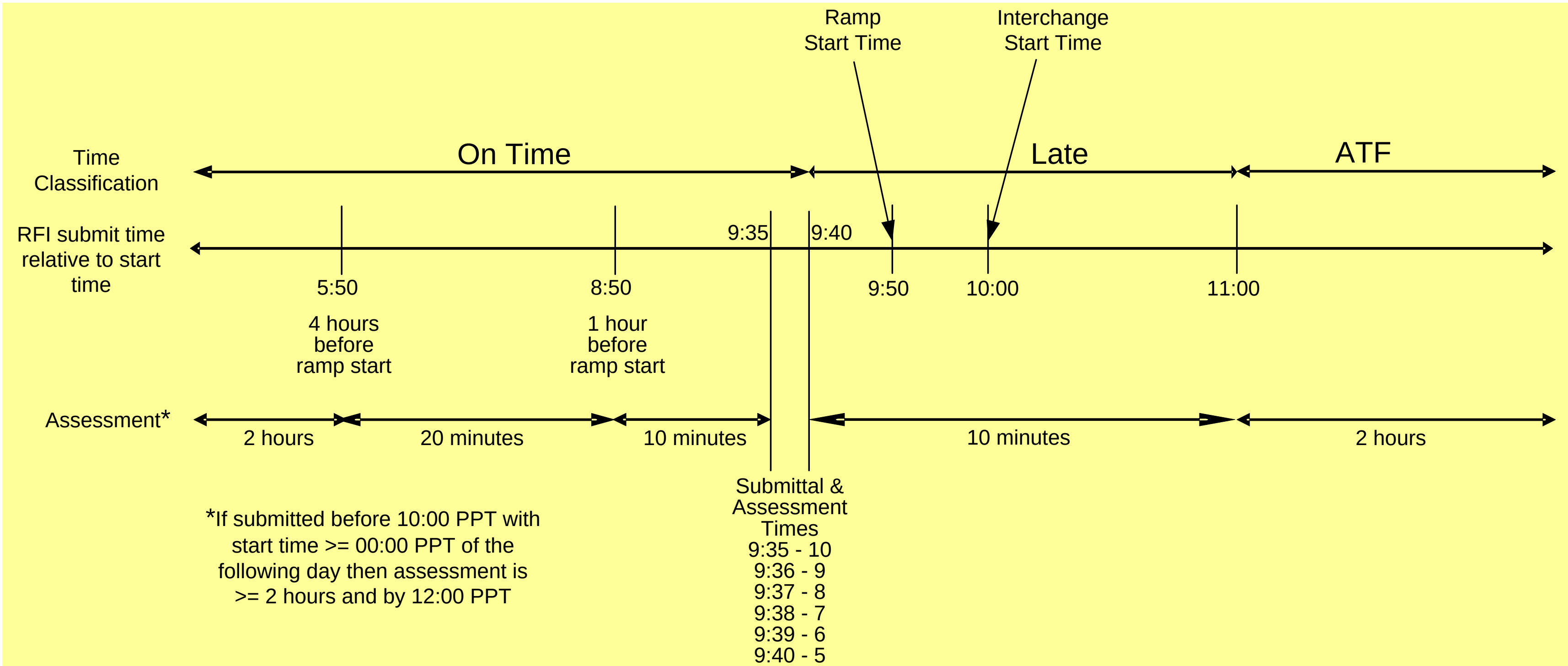


Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange (RFI)[3] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
10 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 6 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
12 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 7 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 8 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 9 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1hour and < 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	< 20 minutes from Arranged interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time	≤ 1minute from RFI submission	By 12:00 PPT of day the Arranged Interchange was received by the IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC



A. Introduction

1. **Title:** **Implementation of Interchange**

2. **Number:** **INT-009-1**

3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority such that the Balancing Authorities implement the Interchange exactly as agreed upon in the Interchange confirmation process.

4. **Applicability**

   4.1. Balancing Authority.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.

C. Measures

M1. The Balancing Authority shall provide evidence that Implemented Interchange matches Confirmed Interchange as submitted by the Interchange Authority.

M2. Evidence shall demonstrate that the Interchange was implemented in the Balancing Authority's Area Control Error (ACE) equation, or the system that calculates the ACE equation. Evidence may be on a net basis or an individual Interchange basis.

M3. Balancing Authorities that are interconnected with a direct current tie shall demonstrate that the Interchange was implemented in the ACE equation or modeled as an equivalent generator/load within its area.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.

   1.3. Data Retention

   The Balancing Authority and Interchange Authority shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

   1.4. Additional Compliance Information

   Each Balancing Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

   Subsequent to the initial compliance review, compliance may be:

   1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Balancing Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authorities shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate a Balancing Authority implemented all instances of the Interchange Authority's communication under R1 concerning the implementation of a Confirmed Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicates a Balancing Authority implemented the Interchange Authority's communication under R1 concerning the implementation of the Confirmed Interchange for that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not implementing a Confirmed Interchange as described in R1.

2.2. Level 2: Two occurrences[1] of not implementing a Confirmed Interchange as described in R1.

2.3. Level 3: Three occurrences[1] of not implementing a Confirmed Interchange as described in R1.

2.4. Level 4: Four or more occurrences[1] of not implementing a Confirmed Interchange as described in R1 or no evidence provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

[1] This does not include instances of not implementing due to extenuating circumstances approved by the Compliance Monitor.

A. Introduction

1. Title: **Interchange Coordination Exemptions**

2. Number: **INT-010-1**

3. Purpose: Allow certain types of Interchange schedules to be initiated or modified by reliability entities, and to be exempt from compliance with other Interchange Standards under abnormal operating conditions.

4. Applicability

4.1. Balancing Authority.

4.2. Reliability Coordinator.

5. Effective Date: January 1, 2007

B. Requirements

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required.

R2. For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event.

R3. For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event.

C. Measures

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence it submitted Arranged Interchange per Requirement 1.

M2. The Reliability Coordinator that directs a modification to an existing Interchange shall have evidence that a directive was issued to submit the Arranged Interchange in accordance with Requirement 2.

M3. The Reliability Coordinator that directs the initiation of a new Interchange shall have evidence that a directive was issued to submit the Arranged Interchange in accordance with Requirement 3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last noncompliance to R1, R2, or R3.

1.3. Data Retention

The Balancing Authority and Reliability Coordinator shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Balancing Authority and Reliability Coordinator shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Balancing Authorities and Reliability Coordinators, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authority and Reliability Coordinator shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate a Balancing Authority or Reliability Coordinator acted in compliance with INT-010. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicates a Balancing Authority or Reliability Coordinator failed to act in compliance with INT-010.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 One occurrence of not submitting an Arranged Interchange as described in R1.

2.1.2 One occurrence of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.2. Level 2: There shall be a level two non-compliance if either of the following conditions is present:

2.2.1 Two occurrences of not submitting an Arranged Interchange as described in R1.

2.2.2 Two occurrences of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions is present:

2.3.1 Three occurrences of not submitting an Arranged Interchange as described in R1.

2.3.2 Three occurrences of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.4. Level 4: There shall be a level three non-compliance if any of the following conditions is present:

2.4.1 Four or more occurrences of not submitting an Arranged Interchange as described in R1.

2.4.2 Four or more occurrences of not directing the submittal of a new or modified Arranged Interchange as described in Requirements 2 or 3.

2.4.3 No evidence provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Standards Announcement Reminder

Project 2008-12 Coordinate Interchange Standards

Ballots and Non-Binding Polls now open through November 13, 2013

Now Available

Ballots for the standards and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels is now open through **8:00 p.m. Eastern on Wednesday, November 13, 2013**.

The standards involved in this project are:

- **INT-004-3 -** Dynamic Transfers
- **INT-006-4 -** Evaluation of Interchange Transactions
- **INT-009-2 -** Implementation of Interchange
- **INT-010-2 -** Interchange Initiation and Modification for Reliability
- **INT-011-1 -** Intra-Balancing Authority Transaction Identification

Background information for this project, can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standards by clicking here.

As a reminder, this ballot is being conducted under the revised Standard Processes Manual, which requires all negative votes to have an associated comment submitted (or an indication of support of another entity's comments). Please see NERC's announcement regarding the balloting software updates and the guidance document, which explains how to cast your ballot and note if you've made a comment in the online comment form or support another entity's comment.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

Standards Development Process

The Standard Processes Manual 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 Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

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Standards Announcement

Project 2008-12 Coordinate Interchange Standards

Comment Period: September 30, 2013 – November 13, 2013
Ballot Pools Forming Now: September 30, 2013 – October 29, 2013

Upcoming:
Ballots and Non-Binding Polls: November 4-13, 2013

Now Available

A 45-day formal comment period for **Project 2008-12-Coordinate Interchange Standards** is open through **8 p.m. Eastern on Wednesday, November 13, 2013**. This project includes five INT standards, a set of new and revised NERC Glossary definitions, a proposed implementation plan, and associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). Ballot pools are being formed and the ballot pool window is open through 8 a.m. Eastern on **Tuesday, October 29, 2013** *(please note that ballot pools close at **8 a.m. Eastern** and mark your calendar accordingly).*

The standards involved in this project are:

- **INT-004-3 -** Dynamic Transfers
- **INT-006-4 -** Evaluation of Interchange Transactions
- **INT-009-2 -** Implementation of Interchange
- **INT-010-2 -** Interchange Initiation and Modification for Reliability
- **INT-011-1 -** Intra-Balancing Authority Transaction Identification

Please note that redlines to the last approved versions of the standards are not posted, as this project has consolidated nine standards into five.

Background information for this project, can be found on the project page.

Instructions for Joining Ballot Pool(s)

For stakeholder convenience, a single ballot pool is being formed for the balloting of all five standards, the implementation plan, and the definitions. The ballot pool that is formed will be used to create six individual ballots (one for each of the five standards and one for the implementation plan and definitions). A separate ballot pool is being formed for the associated non-binding polls and will be used to create five individual non-binding polls (one for each standard's associated VRFs and VSLs). Registered Ballot Body members must join the ballot pools to be eligible to vote in the balloting and submit an opinion for the non-binding polls of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

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.) Two ballot pool list servers have been set up (one for the standards and one for the non-binding polls) and can be used for communication on each of the standards being balloted and non-binding polls for this project. The list servers for this project are:

INT Standards: bp-2008-12_INT_Stds_bp_in
INT Non-binding polls: bp-2008-12_INT_NBP_bp_in

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Wednesday, November 13, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

Ballots for the standards and non-binding polls of the associated VRFs and VSLs will be conducted as previously outlined.

Standards Development Process

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Standards Announcement

Project 2008-12 Coordinate Interchange Standards

Comment Period: September 30, 2013 – November 13, 2013
Ballot Pools Forming Now: September 30, 2013 – October 29, 2013

Upcoming:
Ballots and Non-Binding Polls: November 4-13, 2013

Now Available

A 45-day formal comment period for **Project 2008-12-Coordinate Interchange Standards** is open through **8 p.m. Eastern on Wednesday, November 13, 2013**. This project includes five INT standards, a set of new and revised NERC Glossary definitions, a proposed implementation plan, and associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). Ballot pools are being formed and the ballot pool window is open through 8 a.m. Eastern on **Tuesday, October 29, 2013** *(please note that ballot pools close at* ***8 a.m. Eastern*** *and mark your calendar accordingly).*

The standards involved in this project are:

- **INT-004-3 -** Dynamic Transfers
- **INT-006-4 -** Evaluation of Interchange Transactions
- **INT-009-2 -** Implementation of Interchange
- **INT-010-2 -** Interchange Initiation and Modification for Reliability
- **INT-011-1 -** Intra-Balancing Authority Transaction Identification

Please note that redlines to the last approved versions of the standards are not posted, as this project has consolidated nine standards into five.

Background information for this project, can be found on the project page.

Instructions for Joining Ballot Pool(s)

For stakeholder convenience, a single ballot pool is being formed for the balloting of all five standards, the implementation plan, and the definitions. The ballot pool that is formed will be used to create six individual ballots (one for each of the five standards and one for the implementation plan and definitions). A separate ballot pool is being formed for the associated non-binding polls and will be used to create five individual non-binding polls (one for each standard's associated VRFs and VSLs). Registered Ballot Body members must join the ballot pools to be eligible to vote in the balloting and submit an opinion for the non-binding polls of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

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.) Two ballot pool list servers have been set up (one for the standards and one for the non-binding polls) and can be used for communication on each of the standards being balloted and non-binding polls for this project. The list servers for this project are:

INT Standards: bp-2008-12_INT_Stds_bp_in
INT Non-binding polls: bp-2008-12_INT_NBP_bp_in

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Wednesday, November 13, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

Ballots for the standards and non-binding polls of the associated VRFs and VSLs will be conducted as previously outlined.

Standards Development Process

The Standard Processes Manual 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.

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Standards Announcement

Project 2008-12 Coordinate Interchange Standards

Ballot and Non-Binding Poll Results

Now Available

Ballots for various Coordinate Interchange Standards, non-binding polls of the associated Violation Risk Factors and Violation Severity Levels, and ballot on the Implementation Plan and definitions concluded at **8 p.m. Eastern on Wednesday, November 13, 2013, Thursday, November 14, 2013 and Friday, November 15, 2013 respectively**.

INT-004-3, INT-006-4, INT-009-2, and INT-011-1 received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

	Ballot	Non-Binding Poll
	Quorum /Approval	Quorum/Supportive Opinions
INT-004-3	76.12% / 67.35%	76.80% / 70.06%
INT-006-4	75.82% / 75.58%	76.80% / 70.51%
INT-009-2	75.82% / 68.40%	77.45% / 72.00%
INT-010-2	75.82% / 58.03%	77.45% / 63.33%
INT-011-1	75.52% / 71.35%	76.47% / 76.25%
Definition and Implementation Plan	76.42 % / 77.82 %	N/A

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, those standards will proceed to a final ballot. If any standards do show the need for significant revisions, they will proceed to an additional ballot.

Standards Development Process

The Standard Processes Manual 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 Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2008-12 INT-004-3 Ballot
Ballot Period:	11/4/2013 - 11/13/2013
Ballot Type:	Ballot
Total # Votes:	255
Total Ballot Pool:	335
Quorum:	**76.12 % The Quorum has been reached**
Weighted Segment Vote:	67.35 %
Ballot Results:	**The standard has passed.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	90	1	36	0.655	19	0.345	0	16	19
2 - Segment 2	8	0.7	6	0.6	1	0.1	0	1	0
3 - Segment 3	79	1	32	0.681	15	0.319	0	15	17
4 - Segment 4	24	1	7	0.467	8	0.533	0	3	6
5 - Segment 5	72	1	22	0.595	15	0.405	0	9	26
6 - Segment 6	49	1	22	0.647	12	0.353	0	6	9
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.2	2	0.2	0	0	0	0	2
9 - Segment 9	2	0.2	1	0.1	1	0.1	0	0	0
10 - Segment 10	7	0.5	5	0.5	0	0	0	1	1
Totals	**335**	**6.6**	**133**	**4.445**	**71**	**2.155**	**0**	**51**	**80**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - AEP)
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke		
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Clark Public Utilities	Jack Stamper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power

				Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPPD)
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	COMMENT RECEIVED
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	COMMENT RECEIVED
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney,FMPA)
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (src)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	Central Lincoln PUD	Steve Alexanderson	Negative	COMMENT RECEIVED
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		

3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy, Inc.)
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Negative	COMMENT RECEIVED
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)

3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney of FMPA)
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Negative	SUPPORTS THIRD PARTY COMMENTS - (Steve Alexanderson, Central Lincoln.)
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA and SPP)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	COMMENT RECEIVED
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	

5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Concur with SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brian Murphy)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra's comments)

5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Hasse, Seattle)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz American Electric Power)
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	COMMENT RECEIVED

6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan		
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see Steve Wallace's comments submitted on behalf of Seminole Electric Cooperative, Inc.)
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett		
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Steve Alexanderson, Central Lincoln)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	

10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer		
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Ballot Results	
Ballot Name:	Project 2008-12 INT-006-4 Ballot
Ballot Period:	11/4/2013 - 11/13/2013
Ballot Type:	Ballot
Total # Votes:	254
Total Ballot Pool:	335
Quorum:	**75.82 % The Quorum has been reached**
Weighted Segment Vote:	75.58 %
Ballot Results:	**The standard has passed.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	90	1	41	0.788	11	0.212	0	19	19
2 - Segment 2	8	0.7	6	0.6	1	0.1	0	1	0
3 - Segment 3	79	1	34	0.791	9	0.209	0	19	17
4 - Segment 4	24	1	8	0.667	4	0.333	0	6	6
5 - Segment 5	72	1	23	0.657	12	0.343	0	11	26
6 - Segment 6	49	1	22	0.71	9	0.29	0	8	10
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.2	2	0.2	0	0	0	0	2
9 - Segment 9	2	0.1	1	0.1	0	0	0	1	0
10 - Segment 10	7	0.5	4	0.4	1	0.1	0	1	1
Totals	**335**	**6.5**	**141**	**4.913**	**47**	**1.587**	**0**	**66**	**81**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke		
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	

1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	COMMENT RECEIVED
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney,FMPA)
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
				SUPPORTS

2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	THIRD PARTY COMMENTS - (src)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy, Inc.)
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	

3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney of FMPA)
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA and SPP)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	COMMENT

				RECEIVED
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brian Murphy)
				SUPPORTS THIRD PARTY

5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Negative	COMMENT RECEIVED
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	COMMENT RECEIVED
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ryan Millard)
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Negative	COMMENT RECEIVED
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan		
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see Steve Wallace's comments submitted on behalf of Seminole Electric Cooperative, Inc.)
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett		
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer		
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Ballot Results	
Ballot Name:	Project 2008-12 INT-009-2 Ballot
Ballot Period:	11/4/2013 - 11/13/2013
Ballot Type:	Ballot
Total # Votes:	254
Total Ballot Pool:	335
Quorum:	**75.82 % The Quorum has been reached**
Weighted Segment Vote:	68.40 %
Ballot Results:	**The standard has passed.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	90	1	35	0.7	15	0.3	0	21	19
2 - Segment 2	8	0.7	6	0.6	1	0.1	0	1	0
3 - Segment 3	79	1	30	0.698	13	0.302	0	19	17
4 - Segment 4	24	1	6	0.5	6	0.5	0	6	6
5 - Segment 5	72	1	19	0.559	15	0.441	0	12	26
6 - Segment 6	49	1	18	0.621	11	0.379	0	10	10
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.2	2	0.2	0	0	0	0	2
9 - Segment 9	2	0.1	1	0.1	0	0	0	1	0
10 - Segment 10	7	0.4	4	0.4	0	0	0	2	1
Totals	**335**	**6.4**	**121**	**4.378**	**61**	**2.022**	**0**	**72**	**81**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke		
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Clark Public Utilities	Jack Stamper	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municpal Power Agency (FMPA))

1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPPD)
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, FMPA)
1	Tennessee Valley Authority	Howell D Scott	Affirmative	

1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (src)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
3	Colorado Springs Utilities	Charles Morgan	Abstain	
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy, Inc.)
3	Florida Power Corporation	Lee Schuster	Affirmative	

3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (Terry R Harbour)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Negative	COMMENT RECEIVED
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney of FMPA)
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	

3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA and SPP)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	COMMENT RECEIVED
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Concur with SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	

5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brian Murphy)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Negative	COMMENT RECEIVED
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase, Seattle)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
				SUPPORTS THIRD PARTY

5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	COMMENTS - (NextEra Energy)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Abstain	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	COMMENT RECEIVED
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ryan Millard)
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		

6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan		
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
6	Southern California Edison Company	Joseph T Marone	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett		
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer		
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2008-12 INT-010-2 Ballot
Ballot Period:	11/4/2013 - 11/13/2013
Ballot Type:	Ballot
Total # Votes:	254
Total Ballot Pool:	335
Quorum:	**75.82 % The Quorum has been reached**
Weighted Segment Vote:	58.03 %
Ballot Results:	**The standard will proceed to an additional ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	90	1	31	0.62	19	0.38	0	21	19
2 - Segment 2	8	0.7	5	0.5	2	0.2	0	1	0
3 - Segment 3	79	1	25	0.595	17	0.405	0	20	17
4 - Segment 4	24	1	4	0.333	8	0.667	0	6	6
5 - Segment 5	72	1	18	0.514	17	0.486	0	11	26
6 - Segment 6	49	1	16	0.552	13	0.448	0	10	10
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.2	1	0.1	1	0.1	0	0	2
9 - Segment 9	2	0.1	1	0.1	0	0	0	1	0
10 - Segment 10	7	0.4	4	0.4	0	0	0	2	1
Totals	**335**	**6.4**	**105**	**3.714**	**77**	**2.686**	**0**	**72**	**81**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO's comments.)
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke		
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida

				Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPPD)
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien)
1	NorthWestern Energy	John Canavan	Negative	COMMENT RECEIVED
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	COMMENT RECEIVED
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)

1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, FMPA)
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (src)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Negative	SUPPORTS THIRD PARTY COMMENTS- MISO
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
3	Colorado Springs Utilities	Charles Morgan	Abstain	
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	

3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy, Inc.)
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Negative	COMMENT RECEIVED
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien - NIPSCO)
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City

				Light Paul Haase's comment)
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney of FMPA)
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA and SPP)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	COMMENT RECEIVED
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (MISO)
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO's comments)
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Concur With SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	New York Power Authority	Wayne Sipperly	Abstain	

5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brian Murphy)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase, Seattle)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO's comments)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)

6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Abstain	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	COMMENT RECEIVED
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan		
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see Steve Wallace's comments submitted on behalf of Seminole Electric Cooperative, Inc.)
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
6	Southern California Edison Company	Joseph T Marone	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		

6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett		
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer		
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy

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Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2008-12 INT-011-1 Ballot
Ballot Period:	11/4/2013 - 11/13/2013
Ballot Type:	Ballot
Total # Votes:	253
Total Ballot Pool:	335
Quorum:	**75.52 % The Quorum has been reached**
Weighted Segment Vote:	71.35 %
Ballot Results:	**The standard has passed.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	90	1	39	0.722	15	0.278	0	16	20
2 - Segment 2	8	0.6	5	0.5	1	0.1	0	2	0
3 - Segment 3	79	1	35	0.729	13	0.271	0	14	17
4 - Segment 4	24	1	7	0.538	6	0.462	0	5	6
5 - Segment 5	72	1	23	0.622	14	0.378	0	9	26
6 - Segment 6	49	1	24	0.727	9	0.273	0	6	10
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.2	2	0.2	0	0	0	0	2
9 - Segment 9	2	0.2	1	0.1	1	0.1	0	0	0
10 - Segment 10	7	0.5	5	0.5	0	0	0	1	1
Totals	**335**	**6.5**	**141**	**4.638**	**59**	**1.862**	**0**	**53**	**82**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz AEP)
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke		
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Clark Public Utilities	Jack Stamper	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke		
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
				SUPPORTS THIRD PARTY

1	Tampa Electric Co.	Beth Young	Negative	COMMENTS - (Frank Gaffney,FMPA)
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (src)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	Central Lincoln PUD	Steve Alexanderson	Negative	COMMENT RECEIVED
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	

3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy, Inc.)
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney of FMPA)
3	Tennessee Valley Authority	Ian S Grant	Affirmative	

3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA and SPP)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	COMMENT RECEIVED
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Concur with SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(NextEra)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brian Murphy)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase, Seattle)

5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz American Electric Power)
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	COMMENT RECEIVED
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	

6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan		
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett		
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Steve Alexanderson, Central Lincoln)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer		
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Ballot Results	
Ballot Name:	Project 2008-12 Def and IP Ballot
Ballot Period:	11/4/2013 - 11/15/2013
Ballot Type:	Ballot
Total # Votes:	256
Total Ballot Pool:	335
Quorum:	**76.42 % The Quorum has been reached**
Weighted Segment Vote:	77.82 %
Ballot Results:	**The definition has passed.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	90	1	36	0.766	11	0.234	0	26	17
2 - Segment 2	8	0.7	5	0.5	2	0.2	0	1	0
3 - Segment 3	79	1	29	0.806	7	0.194	0	24	19
4 - Segment 4	24	0.9	7	0.7	2	0.2	0	9	6
5 - Segment 5	72	1	19	0.655	10	0.345	0	17	26
6 - Segment 6	49	1	19	0.731	7	0.269	0	13	10
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.2	2	0.2	0	0	0	1	1
9 - Segment 9	2	0.1	1	0.1	0	0	0	1	0
10 - Segment 10	7	0.6	6	0.6	0	0	0	1	0
Totals	**335**	**6.5**	**124**	**5.058**	**39**	**1.442**	**0**	**93**	**79**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz)
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Clark Public Utilities	Jack Stamper	Abstain	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (FPL/NextEra)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))

1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney,FMPA)
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
				SUPPORTS THIRD PARTY

2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENTS - (IRC SRC)
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (src)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila		
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy, Inc.)
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	

3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	

4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
5	Amerenue	Sam Dwyer	Abstain	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Brian Murphy)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Negative	COMMENT RECEIVED
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz		
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz American Electric Power)
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon TO)
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	COMMENT RECEIVED
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)

6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ryan Millard)
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan		
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Abstain	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett		
8	Montana Consumer Counsel	Larry P. Nordell	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Non-Binding Poll Results

Project 2008-12 INT-004-3

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2008-12 INT-004-3 Non-Binding Poll
Poll Period:	11/4/2013 - 11/14/2013
Total # Opinions:	235
Total Ballot Pool:	306
Summary Results:	76.80% of those who registered to participate provided an opinion or an abstention; 70.06% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Clark Public Utilities	Jack Stamper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		

1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Abstain	

1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	COMMENT RECEIVED
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney,FMPA)
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	

1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (src)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT

				RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy, Inc.)
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY

NERC

				COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA and SPP)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	COMMENT RECEIVED
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	

5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Concur With SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego		

5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brian Murphy)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Abstain	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	Xcel Energy, Inc.	Liam Noailles		

6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	COMMENT RECEIVED
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan		
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)

6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see Steve Wallace's comments submitted on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett		
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2008-12 INT-006-4

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2008-12 INT-006-4 Non-Binding Poll
Poll Period:	11/4/2013 - 11/14/2013
Total # Opinions:	235
Total Ballot Pool:	306
Ballot Results:	76.80% of those who registered to participate provided an opinion or an abstention; 70.51% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		

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1	Deseret Power	James Tucker		
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power	Kevin White	Affirmative	

	Cooperative			
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	COMMENT RECEIVED
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney,FMPA)
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan	Abstain	

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		Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (src)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
3	Colorado Springs Utilities	Charles Morgan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities Group comments)
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	

3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy, Inc.)
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Negative	NO COMMENT RECEIVED
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (SERC)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA and SPP)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	COMMENT RECEIVED
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	

5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		

5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brian Murphy)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Abstain	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	Xcel Energy, Inc.	Liam Noailles		

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6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (CSU Comments)
6	Con Edison Company of New York	David Balban	Abstain	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	COMMENT RECEIVED
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan		
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS

				THIRD PARTY COMMENTS - (SERC)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see Steve Wallace's comments submitted on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett		
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2008-12 INT-009-2

Ballot Results	
Non-Binding Poll Name:	Project 2008-12 INT-009-2 Non-Binding Poll
Poll Period:	11/4/2013 - 11/14/2013
Total # Opinions:	237
Total Ballot Pool:	306
Summary Results:	77.45% of those who registered to participate provided an opinion or an abstention; 72.00% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Clark Public Utilities	Jack Stamper	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	

1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power	Kevin White	Affirmative	

	Cooperative			
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, FMPA)
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		

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1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (src)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
3	Colorado Springs Utilities	Charles Morgan	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS

				THIRD PARTY COMMENTS - (NextEra Energy, Inc.)
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (Terry R. Harbour)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	

3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA and SPP)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	

5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Concur with SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale	David Gordon		

	Electric Company			
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brian Murphy)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Abstain	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		

5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Abstain	
6	Con Edison Company of New York	David Balban	Abstain	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	COMMENT RECEIVED
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ryan Millard)
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan		
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS

				THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
6	Southern California Edison Company	Joseph T Marone	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett		
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2008-12 INT-010-2

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2008-12 INT-010-2 Non-Binding Poll
Poll Period:	11/4/2013 - 11/14/2013
Total # Opinions:	237
Total Ballot Pool:	306
Summary Results:	77.45% of those who registered to participate provided an opinion or an abstention; 63.33% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Negative	SUPPORTS THIRD PARTY COMMENTS - (Group CSU)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		

1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	

1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	COMMENT RECEIVED
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, FMPA)

1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (src)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
3	Colorado Springs Utilities	Charles Morgan	Abstain	

3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy, Inc.)
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	

3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney of FMPA)
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA and SPP)
4	Consumers Energy Company	Tracy Goble	Affirmative	

4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	COMMENT RECEIVED
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Concur with SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		

5	Colorado Springs Utilities	Kaleb Brimhall	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brian Murphy)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Abstain	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	

5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Abstain	
6	Con Edison Company of New York	David Balban	Abstain	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	COMMENT RECEIVED
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED

6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan		
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Steve Wallace will be submitting comments on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
6	Southern California Edison Company	Joseph T Marone	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		

6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett		
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2008-12 INT-011-1

Ballot Results	
Non-Binding Poll Name:	Project 2008-12 INT-011-1 Non-binding Poll
Poll Period:	11/4/2013 - 11/14/2013
Total # Opinions:	234
Total Ballot Pool:	306
Summary Results:	76.47% of those who registered to participate provided an opinion or an abstention; 76.25% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Clark Public Utilities	Jack Stamper	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		

1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke		
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power	Kevin White	Affirmative	

	Cooperative			
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, FMPA)
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		

2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (src)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED

3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy, Inc.)
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		

3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Negative	SUPPORTS THIRD PARTY COMMENTS - (Steve Alexanderson, Central Lincoln.)
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA and SPP)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	

5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Concur with SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	

5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brian Murphy)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Abstain	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	

6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	COMMENT RECEIVED
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan		
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra

				Energy)
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett		
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (41 Responses)
Name (26 Responses)
Organization (26 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (7 Responses)
Comments (41 Responses)
Question 1 (32 Responses)
Question 1 Comments (34 Responses)
Question 2 (31 Responses)
Question 2 Comments (34 Responses)
Question 3 (32 Responses)
Question 3 Comments (34 Responses)
Question 4 (31 Responses)
Question 1 Comments (34 Responses)
Question 5 (29 Responses)
Question 5 Comments (34 Responses)
Question 6 (29 Responses)
Question 6 Comments (34 Responses)
Question 7 (24 Responses)
Question 7 Comments (34 Responses)
Question 8 (22 Responses)
Question 8 Comments (34 Responses)
Question 9 (24 Responses)
Question 9 Comments (34 Responses)
Question 10 (24 Responses)
Question 10 Comments (34 Responses)
Question 11 (24 Responses)
Question 11 Comments (34 Responses)
Question 12 (21 Responses)
Question 12 Comments (34 Responses)
Question 13 (23 Responses)
Question 13 Comments (34 Responses)
Question 14 (24 Responses)
Question 14 Comments (34 Responses)
Question 15 (23 Responses)
Question 15 Comments (34 Responses)
Question 16 (20 Responses)
Question 16 Comments (34 Responses)
Question 17 (21 Responses)
Question 17 Comments (34 Responses)
Question 18 (24 Responses)

Question 18 Comments (34 Responses)
Question 19 (23 Responses)
Question 19 Comments (34 Responses)
Question 20 (19 Responses)
Question 20 Comments (34 Responses)
Question 21 (19 Responses)
Question 21 Comments (34 Responses)
Question 22 (19 Responses)
Question 22 Comments (34 Responses)
Question 23 (19 Responses)
Question 23 Comments (34 Responses)
Question 24 (18 Responses)
Question 24 Comments (34 Responses)
Question 25 (0 Responses)
Question 25 Comments (34 Responses)

Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Agree
I support the comments submitted by Steve Alexanderson with Central Lincoln / Western Small Entity Comment Group
Group
Northeast Power Coordinating Council
Guy Zito
No
Yes
It isn't clear in what manner the entities listed in 5.1 through 5.5 shall be notified by the BA of the Confirmed Interchange.
No
Yes
The notation “4.2” in Section A4 Applicability should be removed. Suggest revising Requirement R2 as follows: R2. Each Sink Balancing Authority shall submit a Reliability Adjustment Arranged Interchange reflecting that modification within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. With the wording change, corresponding changes must be made to the Measures and the VSLs as appropriate. The above wording change to R2 is also proposed for the other requirements in this standard where applicable.
No

No
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
In Section B1.2 – Evidence Retention, R2 in the first bullet should read R3, the R3 in the next bullet should read R2 since R3 applies to BA while R2 applies to the TSP.
Yes
Yes
Agree with the VRFs and VSLs.
Individual
Silvia Parada Mitchell
NextEra Energy/Florida Power and Light
Yes
This standard appears to be more directed at correcting a perceived inequity in congestion management procedures than in promoting or ensuring real-time reliability. If the industry believes congestion management procedures require enhancements related to Dynamic Schedules and Pseudo-Ties, there are much more efficient and less burdensome means to achieve this goal than to put in place this reliability standard. For example, NERC could require a LSE or BA to post near real-time flows for Dynamic Schedules and Pseudo-ties on System Data Exchange (SDX) so that congestion management procedures could have access to more accurate current-hour data than anything provided in this burdensome and administrative standard, which also means it should be more closely considered under the paragraph 81 criteria. Issues with the individual requirements are as follows: R1 requires a LSE to submit an

on-time RFI that will never be implemented in a real-time EMS system and in no way impacts real-time flows and thus, reliability. It is an administrative function and provides no actual real-time reliability benefits, and, thus, should be deleted under paragraph 81 criteria. R2 does not require a LSE to do anything, regardless of the size of a deviation, if the LSE does not expect the same deviation to persist. Updating future hours based on a deviation last hour does nothing for the current hour real-time reliability, which is what the congestion management procedures are intended to deal with. Additionally, these requirements needlessly expose a LSE to potential violations and fines if an auditor chooses, well after the fact, to second guess the LSE's decision about not updating a RFI that never gets implemented in an EMS. R3 is putting the cart before the horse. It requires a BA to register a Pseudo-Tie in a non-existing registry proposed by this requirement to be administered by NAESB, an entity not responsible for reliability, in order to support congestion management procedures. It is both unclear and hard to fathom how requiring a BA to resister a Pseudo-Tie in a registry does anything for reliability when no reliability standard requires any entity to utilize this data for anything. Further, this requirement is not just an administrative task, but a future administrative task that provides no discernible reliability benefits, and, thus, should be deleted under paragraph 81 criteria.
Yes
This standard is primarily a proposed business practice and should be mostly transferred to NAESB and replaced with a single requirement that captures the single reliability essence contained in the standard. Proposed language for the requirement is as follows: R1. Each Balancing Authority and Transmission Service Provider that receives an Arranged Interchange shall evaluate it with respect to their respective obligation pursuant to the Arranged Interchange to ensure it is accurate, complete and that they have the resources, facilities and capability to implement the Arranged Interchange as Confirmed Interchange prior to approving the Arranged Interchange to be transitioned to Confirmed Interchange. Any requirements above or beyond this R1 should be driven by market needs, not a NERC reliability standard. Additionally, the timing requirements in Attachment 1 are arbitrary, not reliability based and are better determined based on market needs through NAESB then by NERC through a reliability standard. As long as Arranged Interchange is evaluated from a reliability prospective the BA's and TSP's prior to being transitioned to Confirmed Interchange, any reliability issues related to the interchange transactions should be identified and addressed by the Balancing Authorities and Transmission Service Providers.
Yes
R1, R2 and R3 should be replaced with a single requirement that better captures the stated purpose of this standard ("To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process and maintain the generation-to-load balance.") The proposed single requirement is: R1. Each Balancing Authority that receives a non-dynamic Confirmed Interchange shall implement such Confirmed Interchange prior to the later of i) the start of the ramp; and ii) one minute after a non-dynamic Arranged Interchange is transitioned to Confirmed Interchange. Issues with the individual requirements are as follows: R1 seems to partially reflect some party's business practice and is more suitable for

adaption by NAESB than NERC. While, with some work, it could help identify instants when a BA failed to properly implement a schedule transaction, it does not require a BA to actually "implement Interchange as agreed upon in the Interchange confirmation process", which is the stated purpose of this standard. It also allows BA's to agree to hourly or multiple-hour Composite Confirmed Interchange, and allows agreements to be reached before, after or during the time the Composite Confirmed Interchange occurs or even once a month. R2 does not add anything obligation on a BA to "ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process" and does not belong in this standard. Clearly, its inclusion in this standard is an attempt to remedy a perceived deficiency in BAL-005-.2b. The appropriate place to fix such deficiency, if indeed BAL-005-.2b is deficient, is within BAL-005.2b, not INT-009-2. R3 is unnecessary, just like it is unnecessary to include a requirement that requires each BA in whose area the generation is controlled shall coordinate the Confirmed Interchange with the Generation Operator of the generation if applicable. Any BA that contains a DC tie already has processes and procedures for coordinating its use just like all BA's have with individual generators within their BA. If the industry believes the better processes or procedures are required, NAESB is a more appropriate organization to develop them than NERC. Finally, if the phrase "and maintain the generation-to-load balance" contained in the Purpose statement seems to be out of place and extraneous to implementing the Interchange as agreed upon. By removing it, the purpose is better focused.
Yes
This standard appears to be more directed a correcting a perceived inequity in congestion management procedures and/or in energy sharing agreements for reliability than in promoting or ensuring real-time reliability. R1, R2 and R3 should be retired (using the paragraph 81 criteria), and possibly transferred to NAESB. They do nothing to impact real-time reliability, and could actually adversely impacts reliability if a RFI for reliability fails to get implemented within the arbitrary 60 minute windows specified in these requirements and the energy scheduled for reliability reasons prematurely ends. Additionally, any limitations on how long energy sharing transactions or RC directed schedules for reliability reason should be exempted from standard interchange scheduling processes and procedures should be addressed by NAESB, not NERC. Finally, R4 does not belong in an INT standard. It is unclear how capping the MW value in ACE equations helps ensure reliability. While a cap may change which BA supplies the energy above the MW cap, it does nothing to ensure the flow through the metering point where the dynamic signal emanates from ever changes. Additionally, if it belongs in a reliability standard at all, it should be included in a BAL standard.
No
This standard appears to be more directed a correcting a perceived inequity in congestion management procedures than in promoting or ensuring real-time reliability. It is also basically an administrative task that does not alter or have any effect on real-time operations, and, thus should be eliminated using the paragraph 81 criteria. If the industry believes congestion management procedures require enhancements related to intra-Balancing Authority Area transfers, there are much more efficient and less burdensome means to achieve this goal than

to put in place this reliability standard. For example, NERC could require a LSE to post data related to current-hour schedules for real-time intra-Balancing Authority Area transfers on System Data Exchange (SDX) so that congestion management procedures could have access to such data. Additionally, many BA may have practices that already require entities to submit an RFI related to intra-Balancing Authority Area transfers within or through their BA for energy imbalance calculations and/or for identifying unreserved use. Alternatively, if the drafting team determines a requirement is require for reliability, R1 should be modified to read as follows: R1. Each Load-Serving Entity that uses Point to Point Transmission Service or Network secondary Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange. The phrase “unless the information about intra-Balancing Authority Area transfers is included in congestion management procedure(s) via an alternate method” adds nothing to the requirement. If the sole reason for this requirement is to get data related to intra-Balancing Authority Area transfers into congestion management procedure, the requirement is not needed for reasons stated above.
Individual
Thomas Foltz
American Electric Power
Yes
Pseudo-Ties and Dynamic Schedules are handled by two different Functional Entities. Dynamic Schedules are managed by PSE’s while Pseudo-Ties require input from LSE’s. We recommend that this work be separated from R1 into different requirements and that PSE be added to the Applicability section. We would like the project team to provide some insight on why definitions for were needed for Attaining Balancing Authority and Native Balancing Authority rather than utilizing Source Balancing Authority and Sink Balance Authority. Definition of Arranged Interchange - We recommend the definition be changed to the following: The state where the Interchange Sink Balancing Authority has received the RFI or intra-Balancing Authority transfer information (initial or revised). Our negative vote on this standard is primarily driven by our recommendation that the PSE be added to the Applicability section.
No
No
No
No
AEP sees no reliability benefit to the BES from INT-011-1 and encourage the drafting team to not pursue it.
No
No

Please see our response to Question 1.
No
Please see our response to Question 1.
Individual
Steve Alexanderson
Central Lincoln
Yes
Suggest changing "4.2. Load-Serving Entity" to "4.2. Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie." This better matches the trend to more explicitly state the applicability within the applicability section.
No
No
No
No
Yes
Suggest changing "4.1.1. Load-Serving Entities" to "4.1.1. Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers." This better matches the trend to more explicitly state the applicability within the applicability section.
Individual
Joe O'Brien
NIPSCO
No
No
No
Yes
Per MISO recommendation: R2.3 of INT-004 states that the LSE is responsible maintaining the RFI for Reliability Adjustment requests. INT-010 R4 seems to transfer that same activity to the BA role. We request to remove Requirement #4 from INT-010.
No
No
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Individual
d
s
rrr
No
No
No
No
No
No
No
No
No
No
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No
No
No
No
No
No
No
No
No
Will this show up on the summary page?
Individual
Shirley Mayadewi

Manitoba Hydro
Yes
(a) Manitoba Hydro does not agree with the INT-004-3 Draft 3 changes (issued September 17, 2013) to R1 and R2. The CISDT had previously incorporated stakeholder's suggestions in both Draft 1 (issued November 10, 2009) and Draft 2 (issued July 12, 2013) to address tagging Dynamic Transfers in the absence of a forecast. Subsequently in Draft 3 (after the 30-day informal comment period following Draft 2) the CISDT, in addressing a stakeholder's concern with the word 'expected' in the term "expected maximum", made modifications to both R1 and R2, including deleting in its entirety the bulleted statement which contained the word that were the subject of the stakeholder comment. Such modification indirectly implies a forecast is possible. Manitoba Hydro would respectfully like to point out that there are instances in which an LSE cannot forecast Dynamic Transfers, such as market transactions were ISOs dispatch energy and/or ancillary services based on economic price signals. In such instances tagging at a maximum value is appropriate to ensure reliability. Currently the language of Requirement R1 and R2 is not sufficiently clear to indicate to the LSE what value should properly be included in the energy profile for the Dynamic Transfer tag. The Rationale Statement (which will be removed from the requirement in any event once the standard is finalized) refers only to a scenario where a forecast is available, and leaves it open to interpretation what value should be included where a forecast is not available. Our preference is to see clear direction given to the Responsible Entity in the language of the standard itself as to the appropriate values for inclusion in Dynamic Transfer tags. As a solution, Manitoba Hydro suggests (i) returning to the Draft 1 / Draft 2 language for R1 and R2, or in the alternative, (ii) returning to the Draft 1/Draft 2 language for R1 and R2 but in order to remove confusion, replace the term "expected maximum" in R1 with "maximum" or "capped maximum". (b) The term "Dynamic Transfer" is used in the two new proposed definitions. Dynamic Transfer is a defined term in the NERC Glossary - is it meant to be capitalized here? (c) The definitions seem to indicate that Pseudo-Tie has a lower case 't'. However, throughout the standards, Pseudo-Tie has a capital 'T'. (This applies to all the Interchange Standards reviewed here). (d) M1 – Words seem to be missing from the first sentence. Sentence should end with 'Pseudo-ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-tie." (e) M3 – includes the words 'prior to its implementation' which do not appear in the requirement itself.
Yes
(a) Purpose – wondering whether the reference to 'entities' should more appropriately be 'responsible entities' (b) R1 – the use of the word 'expect' is very open. Without further qualifying language, parties will proceed on the assumption that this is completely within the Balancing Authority's own judgment. (c) M1 – there is no measure that addresses the requirement 1.1 and 1.2 (d) M2 – the language of this measure does not match the language of the requirement. In order to be consistent with the language of the requirement, the measure should read "….that it responded to each Arranged Interchange or emergency Arranged Interchange within the time defined in Attachment 1…" (e) M3 – the language of the measure does not match the language of the requirement with respect to the communication

of the denial. It should appropriately read "…or denied the request and, if applicable, communicated denial to the Reliability Coordinator…." (f) M5 – 'is' should be 'was'
Yes
(a) R1 – the word 'Adjacent' should be added before the words 'Balancing Authority' in the second line. (b) M1 – the language of the measure is missing a few concepts that are in the requirement. i.e. 'and Pseudo-ties' should be added after Dynamic Schedules', and 'by a Reliability Coordinator' should be added after 'as directed'. (c) R2, M2 (and VSLs) – the standard uses the term Net Interchange Actual but the Glossary defined term which I assume is desired to be used is Net Actual Interchange.
Yes
(a) M2 and M3 – use the language 'created' instead of 'submitted' as used in the corresponding requirements.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
(a) VSLs, R1, seems to be missing the word 'but' after the word 'Pseudo-tie'
Yes
(a) VSLs, R1, R2 – the words 'transition to Confirmed Interchange' do not reflect the language of the requirement and should be deleted (b) VSLs, R1 – there is no VSL related to the failure of the Balancing Authority to curtail a Confirmed Interchange (c) VSLs, R5, High VSL vs. Severe VSL – it's currently difficult to decipher the difference between these two. Is the Severe VSL meant to be the failure to notify any of the entities?
Yes

(a) VSLs, R1 – the last words of this VSL is ‘for that hour’ but that concept doesn’t appear in the requirement or standard. The requirement refers to ‘mutually agreed upon time interval’ and the VSL should reflect that.
Yes

Group
Seattle City Light
Paul Haase
NextEra
Yes
This proposed standard is a major change in the policy and how the Pseudo Ties have been used in the past. To date a number of Transmission Service Providers created some Business Practices (BP) requiring tagging of Pseudo Ties, there was no requirement in the NERC standards to do so. Seattle City Light does not feel there is a need for change at this time, and supports the position of NextEra regarding this proposed Standard. A second aspect of this change is the possible compliance implications. While the violation of Business Practices usually has some financial penalties these penalties do not have the same weight as violations of reliability standards. So implementation of this Standard as currently proposed will put entities in double jeopardy not only facing penalties for Business Practice violations but also NERC Standard violations. Seattle’s preferred position is that all INT standards should be removed from the Reliability Standards and move to the Business Practices currently being implemented by NAESB, because they more closely represent commercial practices rather than reliability requirements. If this is not realistic and possible for the present INT development project (but may occur in the follow-up activities to the NERC Independent Expert Review) Seattle recommends the following language changes to the standard draft (new text in CAPS, cuts indicated by <deleted text>): 1. Add the following exclusion in R.1 R1. Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method, OR ATTAINING AND SINK BALANCING AUTHORITIES ARE THE SAME. 2. Change R.2 as follows. R2. Each Load-Serving Entity that submits a Request For Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours <delete in order to support> WHEN congestion management procedures ARE IN EFFECT and if any one of the following occurs: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same Day Operations, Real Time Operations] 2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than <deleted 10%> 30% for that hour and that deviation is expected to persist THROUGH THE HOURS WHEN CONGESTION MANAGEMENT PROCEDURES ARE IN EFFECT. 2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than <deleted 25> 75 MW for that hour and that deviation is expected to persist THROUGH THE HOURS WHEN

CONGESTION MANAGEMENT PROCEDURES ARE IN EFFECT. 2.3. The Load-Serving Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange THROUGH THE HOURS WHEN CONGESTION MANAGEMENT PROCEDURES ARE IN EFFECT.
No
Yes
Seattle City Light supports the position of Next Era. Specifically: R1, R2 and R3 should be replaced with a single requirement that better captures the stated purpose of this standard (“To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process and maintain the generation-to-load balance.”) The proposed single requirement is: R1. Each Balancing Authority that receives a non-dynamic Confirmed Interchange shall implement such Confirmed Interchange prior to the later of i) the start of the ramp; and ii) one minute after a non-dynamic Arranged Interchange is transitioned to Confirmed Interchange. Issues with the individual requirements are as follows: R1 seems to partially reflect some party’s business practice and is more suitable for adaption by NAESB than NERC. While, with some work, it could help identify instants when a BA failed to properly implement a schedule transaction, it does not require a BA to actually “implement Interchange as agreed upon in the Interchange confirmation process”, which is the stated purpose of this standard. It also allows BA’s to agree to hourly or multiple-hour Composite Confirmed Interchange, and allows agreements to be reached before, after or during the time the Composite Confirmed Interchange occurs or even once a month. R2 does not add anything obligation on a BA to “ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process” and does not belong in this standard. Clearly, its inclusion in this standard is an attempt to remedy a perceived deficiency in BAL-005-.2b. The appropriate place to fix such deficiency, if indeed BAL-005-.2b is deficient, is within BAL-005.2b, not INT-009-2. R3 is unnecessary, just like it is unnecessary to include a requirement that requires each BA in whose area the generation is controlled shall coordinate the Confirmed Interchange with the Generation Operator of the generation if applicable. Any BA that contains a DC tie already has processes and procedures for coordinating its use just like all BA’s have with individual generators within their BA. If the industry believes the better processes or procedures are required, NAESB is a more appropriate organization to develop them than NERC. Finally, if the phrase “and maintain the generation-to-load balance” contained in the Purpose statement seems to be out of place and extraneous to implementing the Interchange as agreed upon. By removing it, the purpose is better focused.
Yes
Seattle City Light supports the cocnerns of NextEra regarding this draft. Specifically, "This standard appears to be more directed a correcting a perceived inequity in congestion management procedures and/or in energy sharing agreements for reliability than in promoting or ensuring real-time reliability. R1, R2 and R3 should be retired (using the paragraph 81 criteria), and possibly transferred to NAESB. They do nothing to impact real-time reliability, and could actually adversely impacts reliability if a RFI for reliability fails to get implemented within the arbitrary 60 minute windows specified in these requirements and the

energy scheduled for reliability reasons prematurely ends. Additionally, any limitations on how long energy sharing transactions or RC directed schedules for reliability reason should be exempted from standard interchange scheduling processes and procedures should be addressed by NAESB, not NERC. Finally, R4 does not belong in an INT standard. It is unclear how capping the MW value in ACE equations helps ensure reliability. While a cap may change which BA supplies the energy above the MW cap, it does nothing to ensure the flow through the metering point where the dynamic signal emanates from ever changes. Additionally, if it belongs in a reliability standard at all, it should be included in a BAL standard." Regarding R4, Seattle adds that it will be almost impossible to determine or prove that the adjusted value was not exceeded as required in Measure 4. An entity could possibly do that positively if it only had one intertie and one interchange schedule.
No
Seattle City Light supports that comments of NextEra. Specifically, "This standard appears to be more directed a correcting a perceived inequity in congestion management procedures than in promoting or ensuring real-time reliability. It is also basically an administrative task that does not alter or have any effect on real-time operations, and, thus should be eliminated using the paragraph 81 criteria. If the industry believes congestion management procedures require enhancements related to intra-Balancing Authority Area transfers, there are much more efficient and less burdensome means to achieve this goal than to put in place this reliability standard. For example, NERC could require a LSE to post data related to current-hour schedules for real-time intra-Balancing Authority Area transfers on System Data Exchange (SDX) so that congestion management procedures could have access to such data. Additionally, many BA may have practices that already require entities to submit an RFI related to intra-Balancing Authority Area transfers within or through their BA for energy imbalance calculations and/or for identifying unreserved use. Alternatively, if the drafting team determines a requirement is require for reliability, R1 should be modified to read as follows: R1. Each Load-Serving Entity that uses Point to Point Transmission Service or Network secondary Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange. The phrase “unless the information about intra-Balancing Authority Area transfers is included in congestion management procedure(s) via an alternate method” adds nothing to the requirement. If the sole reason for this requirement is to get data related to intra-Balancing Authority Area transfers into congestion management procedure, the requirement is not needed for reasons stated above."
Yes
For this draft to proceed, Seattle City Light requests that the term "intra-Balancing Authority Area transfer" be defined (in addition to the changes suggested by NextEra as indicated in Question 5).
Individual
John Idzior

ReliabilityFirst Corporation
Yes
ReliabilityFirst votes in the affirmative because the modifications to this standard help to ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures. Even though ReliabilityFirst votes in the affirmative, we offer the following for consideration: 1. Requirement R1 a. ReliabilityFirst requests further clarification on the meaning of the term “on-time” which proceeds the term “Arranged Interchange”. Does the “on-time” term have a specific meaning within the context of the standard and if so, ReliabilityFirst recommends making it a defined term.
Yes
ReliabilityFirst votes in the negative because the use of bullets (or statements) in Requirement R4 is not consistent with the wording of the parent requirement. This has the possibility of creating compliance issues and lead to potential interpretations. ReliabilityFirst offers the following comments for consideration: 1. Requirement R1 and R2 a. ReliabilityFirst requests further clarification on meaning of the term “on-time” which proceeds the term “Arranged Interchange”. Does the “on-time” have a specific meaning within the standard and if so, ReliabilityFirst recommends making it a defined term. 2. Requirement R4 a. Requirement R4 States “…that none of the following conditions” and there are three bullets associated with the requirement. Bullets are considered “or” statements in Reliability Standards and ReliabilityFirst believes that these are should be “and” statements. Thus, ReliabilityFirst recommends reformatting the bullets to become sub-parts (i.e., 4.1, 4.2 and 4.3). Without this modification, there is a high probability for potential compliance complications and possible interpretations. 3. VSL Requirement R5 a. The High VSL and the first Severe VSL seem to be saying the same thing. ReliabilityFirst recommends the following for consideration for the High VSL: “The Sink Balancing Authority notified all but one of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.”
Yes
ReliabilityFirst abstains and offers the following comment for consideration: 1. Requirement R1 a. ReliabilityFirst believes Reliability Standards should stand on their own merit and should not reference other Reliability Standards. The reference to INT-010-2 may cause issues if the intent of the INT-010-2 standard changes in the future. Furthermore, with the reference to the INT-010-2 standard the approval of INT-009-2 is completely dependent to the approval of the INT-010-2 (i.e., the approval of the INT-009-2 is dependent on the INT-010-2 standard).
Yes
ReliabilityFirst abstains and offers the following comment for consideration: 1. Requirement R1 a. ReliabilityFirst requests further clarification on meaning of the term “energy sharing agreement”. If this term has a specific meaning that has an impact on the intent of the standard, ReliabilityFirst recommends making it a defined term.
Yes
No
No

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Group
ISO/RTO Standards Review Committee
Greg Campoli
Yes
R3 (Measurement) Will evidence that the BA communicated to the E-tag system, which is then delivered to the RC, within 10 minutes of the denial of the Reliability Adjustment Arranged Interchange suffice as meeting Requirement R3.1? If not, please provide clarification as to why this will not suffice and what additional evidence would be needed. R5. Per FERC Order 764, an RFI may be submitted 20-minutes in advance of start time. Per NERC Standards, that RFI has a 10-minute approval window. If the Ramp Duration of the RFI is 20-minutes, normal system communication may lend itself to a violation of this standard. Recommend the SDT consider the timing implication and revise the requirement so that it is not a zero exceptions requirements.
Yes
Comments: Requirement #3 Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie if applicable. Suggest to remove “if applicable”. If the condition exists, what else would make the condition non-applicable to the standard?

Yes
No
Yes
Yes
No
Comments: Remove the first “Area” in the sentence and add the phrase “within an Interconnection”: A Balancing Authority Area whose Balancing Authority Area that is interconnected within an Interconnection with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
No
Comments: If Sink distribution requirements are going away, why define the Sink as the recipient in this definition. The Sink was removed from Confirmed definition. Proposal: The state where a Request for Interchange or intra-Balancing Authority transfer information (initial or revised) have been submitted for approval from applicable entities. An Arranged Interchange marks the beginning of the Requirement Timing Assessment Period as defined in INT-006.
Yes
No
Comments: As there are no requirements for distribution, nor does this definition supply where the request is coming from, the definition does not also have to define the Sink BA as the recipient of the request. Proposed: A collection of data as defined in the NAESB Business Practice Standards RFI Datasheet, to be submitted to the Interchange Sink Balancing Authority for the purpose of collecting approvals for the implementation of bilateral Interchange between a Source and Sink Balancing Authority or within a single Balancing Authority.
No
There will also be a Sink BA for Interchange Transactions that do not require an Interchange Schedule. Recommend that the phrase “and the resulting Interchange Schedule” be deleted.
No
There will also be a Source BA for Interchange Transactions that do not require an Interchange Schedule. “IS” reference should be removed.
Yes
Yes
No
Recommend revising the definition to add the phrase “within an Interconnection” at the end of the definition.
Yes
Recommend revising the definition to add the phrase “within an Interconnection” at the end of the definition.

Yes
No
Under the VRF justifications language, it is stated that: A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Why then are there no lower VSLs under severe? Propose a tiered VSL level for operational impact.
Individual
Marie Knox
MISO
Yes
Yes
Yes
No
R2.3 of INT-004 states that the LSE is responsible for maintaining the RFI for Reliability Adjustment requests. If the Pseudo-Ties are implemented through an agreed upon alternate congestion management approach (such as reporting market flows or generation-to-load flows to the IDC), the IDC will assign a relief obligation to the BA. The BA will redispatch its system to meet the relief obligation which may or may not involve a change to the pseudo-tie output. In this instance, it is not appropriate to limit the pseudo-tie output in the ACE equation to a reliability cap if other generation is being redispatched to meet the relief obligation. Therefore it is recommended this requirement be removed.
Yes
No
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Group
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
Yes
INT-004-3 R1 states, “Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method.” Can the SDT clarify the reliability benefit for INT-004-3 R3, which requires the registration of Pseudo-Ties in the NAESB Electric Industry Registry prior to implementation? Why is registering pseudo-ties in the NAESB Electric Industry Registry required if R1 has been met?
No
No
No
Yes
No
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Yes
The VSL for INT-004-3 R2 states, “A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.” The reference to future hours, as written, does not have a defined time duration. One suggestion for the duration is current hours plus 2 hours. It is suggested that the VSL for Requirement 3 should have “Attaining” in front of Balancing Authority to correspond to the language of the Requirement.
Yes
Yes
Yes
The VSL for INT-010-2 R4 states, “The Balancing Authority involved in a Pseudo-Tie or Dynamic Schedule failed to ensure that the MW value from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange was not exceeded in its ACE equation.” The VSL does not include a duration of time. It is suggested that a period of time be included in the VSL.
Yes, we agree with these compliance elements.
Group
PacifiCorp
Ryan Millard
No
Yes
Requirement R2.1: It is unclear to PacifiCorp why the drafting team has only referenced “Proper connectivity of adjacent TSPs” that is “invalid” as the criteria required for a denial or curtailment. Highlighting “proper connectivity of adjacent Transmission Service Providers” seems to indicate that connectivity is the only validation that occurs (which is inherently misleading). To align more with the assessment TSPs are required to perform, PacifiCorp suggests adding additional validations where a denial or curtailment would occur (e.g., physical path, transmission profile, transmission limit, valid OASIS reservation, etc.). If the intent of the requirement is to more broadly cover all criteria that would result in the denial or curtailment of the Arranged Interchange and Confirmed Interchange (rather than to reference an exhaustive list of criteria), connectivity should be removed from the requirement or cited as an example. Otherwise, a denial or curtailment for something other than what is explicitly referenced in the requirement could be interpreted as an improper denial or

curtailment. Requirement R3.1: It is unclear to PacifiCorp what the drafting team has intended the word “communicate” to mean under R3.1, as all approvals and denials associated with a Reliability Adjustment Arranged Interchange are “communicated” to the Reliability Coordinator via e-tagging. Additionally, all reasons for a denial are indicated on an e-tag. PacifiCorp would like to understand the rationale for requiring additional communication and the specific method of communication which is required under R3.1.
Yes
Requirement R1: As indicated in our previous comments, it is unclear to PacifiCorp what the distinction is between Net Scheduled Interchange and Composite Confirmed Interchange in Requirement R1. Although Net Scheduled Interchange has been defined as the “algebraic sum of all interchange schedules across a given path” and Composite Confirmed Interchange is based on the “aggregate of all confirmed interchange,” PacifiCorp does not see the two terms as being distinct from one another in practice. To avoid confusion, PacifiCorp recommends keeping Net Scheduled Interchange as the only term referenced in the requirement. Requirement R2: PacifiCorp maintains that the addition of this requirement is redundant. The Rationale for R2 only reinforces this point. If R2 is “equivalent to R10 of BAL-005-2b,” why is the inclusion of R2 in INT-009-2 necessary? Wouldn’t the existence of an “equivalent” requirement in another standard be grounds for its removal under Paragraph 81?
No
Yes
No
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
See PacifiCorp’s comments under INT-009 (above).
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Yes.
Individual
Terry Harbour
MidAmerican Energy
No
No
Yes
Requirement R2: This requirement is redundant. As identified in the rationale box, the requirement is equivalent to BAL-005-2b. To avoid double jeopardy, the R2 requirement in INT-009-2 should be removed and any remaining concerns should be addressed in BAL-005.
No
Yes
No
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual

Chris Scanlon
Exleon Companies
Yes
R1 requires a LSE to submit an on-time RFI that will not be implemented in a real-time EMS system and will not impact reliability. It appears to be an administrative function. R2 does not appear to require a LSE to do anything impacting operations. R3 requires a BA to register a Pseudo-Tie in a non-existing registry proposed by this requirement to be administered by NAESB, an entity not responsible for reliability. This seems unrelated to reliability and premature.
No
Yes
INT-009-2 includes new definitions for Dynamic Schedule and Pseudo-Tie requiring that these values be treated as Interchange Schedules and Actual Interchange, respectively, and included in ACE equations. It is confusing, then, that R1 should specify that Composite Confirmed Interchange is to be calculated without inclusion of Dynamic Schedules and Pseudo-Ties. As Dynamic Transfers represent inputs to the ACE equation, and measurements against which a BA is managing its balancing function, to exclude them from the Composite Confirmed Interchange seems to paint an inaccurate picture of the Interchange between two Balancing Authorities. If the intention is to not skew Composite Arranged Interchange by the inclusion of values that change in Real Time with no settled value available until after-the-fact, that can be accomplished by stipulating that estimated values of Dynamic Schedules and Pseudo-Ties not be included in Composite Confirmed Interchange, and that the real-time values should be used for calculation of Composite Confirmed Interchange in the Real Time horizon, with the agreed on after the fact values used for calculation of Composite Confirmed Interchange in the after the fact horizon.
No
No
Exelon agrees with commnets provided by NextEra for this standard. Addresses congestion management more than reliability. Administrative task that does not alter or have any effect on real-time operations. Alternatively, propose R1 should be modified to read as follows: R1.Each Load-Serving Entity that uses Point to Point Transmission Service or Network secondary Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange.
No
See response to Q 5.
No
See response to INT-009 question.
No
See response to INT-009 question.

Individual
Bill Fowler
City of Tallahassee, TAL
Agree
NextEra
Individual
Jack Stamper
Clark Public Utilities
Agree
Seattle City Light
Individual
John Canavan
NorthWestern Energy
Yes
We beleive the VSL for R2 should be low, not sever because this would not have a negative impact on BES reliability because the values are not included in the ACE equation.
No
Yes
R1 needs more clarification - what does this requirment mean, e.g., what is an energy sharing agreement?
Group
SPP Standards Review Group
Robert Rhodes
Yes
Capitalize 'scheduled Interchange' in the Guidelines and Technical Basis Section to make it consistent with actual Interchange in the same section.
No
Yes
In consideration of the Paragraph 81 effort, we suggest retiring R10 in BAL-005-0.2b. There is no need to have this requirement in both BAL-005-0.2b and INT-009-2. We suggest the following wording for R3: Each Balancing Authority in whose area a high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of that high-voltage direct current tie if applicable. Additionally, we do not understand what the 'if applicable' at the end of the requirement is referring to. Is it

the BA or is it something else? If it is indeed the BA, we suggest deleting the phrase since it doesn't add any clarification to the requirement. If it isn't referring to the BA, then please add additional clarification such that the reference can be understood.
Yes
Delete 4.2 in the Applicability Section. It is blank. In the 4th bullet of the Background Section, we suggest changing the reference to the ACE value to the ACE equation. The bullet would then read: R4 was created to address the fact that when a Reliability Adjustment Arranged Interchange is approved for a Pseudo-Tie or Dynamic Schedule, action is required by the Balancing Authority to ensure that the data source feeding the Net Interchange value in the ACE equation does not exceed the MW value of the Reliability Adjustment Arranged Interchange. Also we suggest the following wording change for R3: Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of that modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons.
Yes
No
No
Change 'real time' to 'Real-time' since it is NERC Glossary Term.
No
Change 'real time' to 'Real-time' since it is NERC Glossary Term.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
We suggest the following change to the definition of Reliability Adjustment Arranged Interchange: A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
Yes
Yes
Yes
Yes
No

We suggest the Severe VSL for R1 be changed to read: 'The Load-Serving Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie but did not ensure that a Request for Interchange…'
Yes
No
We suggest deleting the phrase '…for that hour.' at the end of the Severe VSL for R1.
No
We suggest changing the wording of the Severe VSL for R2 to: The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
Yes
Individual
Scott Langston
City of Tallahassee
Agree
NextEra
Individual
Brett Holland
Kansas City Power & Light
No
No
Yes
BAL-005-0.2b R10 is the same requirement as in INT-009-2 so we have a duplicate requirement in both standards. In order to remove duplication, BAL-005-0.2b R10 could be retired in reference to Paragraph 81. R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie if applicable. One would think BA and TOP coordination over the HVDC would be applicable all the time, would it not? In what conditions would it not be coordinated?
Yes
Background Section -4th bullet, I suggest changing the term "ACE value" to the "ACE equation". The bullet would then read: R4 was created to address the fact that when a Reliability Adjustment Arranged Interchange is approved for a Pseudo-Tie or Dynamic Schedule, action is required by the Balancing Authority to ensure that the data source feeding the Net Interchange value in the ACE equation does not exceed the MW value of the Reliability Adjustment Arranged Interchange
Yes
No

Yes
Typo – need to capitalize Real-time
Yes
Typo – need to capitalize Real-time
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
David Jendras
Ameren
Agree
Ameren supports MISO's comments on the INT standards
Individual
Michael Falvo
Independent Electricity System Operator
No
No
No
Yes
1. The notation "4.2" in Section A4 Applicability should be removed. 2. While we understand and support the intent of Requirement R2, we suggest it be revised as indicated below to remove the term "shall ensure" which may not be measurable. R2. Each Sink Balancing

Authority shall submit a Reliability Adjustment Arranged Interchange reflecting that modification within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. If the SDT accepts the proposed wording change, then please make corresponding changes to the Measures and the VSLs as appropriate. The above wording change to R2 is also proposed for other requirements in this standard, where appropriate.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
In Section B1.2 – Evidence Retention, we believe the R2 in the first bullet should read R3, whereas the R3 in the next bullet should read R2 since R3 applies to BA while R2 applies to the TSP.
Yes
Yes
Group
Duke Energy
Michael Lowman
Yes
Duke Energy recommends combining R2.1 and R2.2 as follows for added clarity for when a Dynamic Schedule or Pseudo-Tie should be updated. “R2.1. For Confirmed Interchange, when the actual hourly integrated energy deviates from the Confirmed Interchange by 25MW or 10%, whichever is greater, for that hour and that deviation is expected to persist.”
Yes
The tasks identified in Requirements 4 and 5 are performed by a third party vendor. Duke

Energy is concerned with how an auditor will measure this requirement and that this would be an administrative burden on the BA. Duke Energy believes the actual reliability based need for R4 and R5 is contingent upon the failure of the third party vendor’s tool and recommend revising the requirements to identify a process to ensure that the tasks preformed in R4 and R5 are completed by a sink BA when there is a failure.
No
No
Yes
No
Yes
Yes
Duke Energy recommends revising the definition as follows: “Pseudo-tie: A time-varying energy transfer that is updated in real time and included in the Net Interchange Actual term in the same manner as a Tie Line in the affected Balancing Authorities’ control ACE equations (or alternate control processes), but for which no physical tie or energy metering actually exists.“
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Duke Energy questions why Attaining BA was used instead of Sink BA. They appear to have the same meaning.
No
Duke Energy questions why Native BA was used instead of Source BA. They appear to have the same meaning.
No
Duke Energy recommends revising the definition as follows, “Operational Planning Analysis: An analysis of the expected system conditions for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as but not limited to load forecast(s), generation output levels, expected Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). “

Yes
Yes
Yes
Yes
Yes
Group
SERC OC Review Group
Rene Free
Yes
The SDT is respectfully requested to clarify that a Pseudo-Tie is not a physical tie that actually exists. In the Table of Compliance, R2 the current draft language is: A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours Suggested addition to Table of Compliance, R2 to make the Severe VSL consistent to the requirements: A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours ADD: if expected to persist.
Yes
The SDT is requested to consider modifying the Reliability Adjustment Arranged Interchange definition. The current definition language is: Reliability Adjustment Arranged Interchange - Request to modify Confirmed Interchange or Implemented Interchange for reliability purposes. Suggested modification follows: DELETE: “Request to modify a” ADD: Modified New definition: Modified Confirmed Interchange or Implemented Interchange for reliability purposes.
Yes
The SDT is respectfully requested to clarify that a Pseudo-Tie is not a physical tie that actually exists.
Yes
The SDT is requested to consider modifying the Reliability Adjustment Arranged Interchange definition. The current definition language is: Reliability Adjustment Arranged Interchange - Request to modify Confirmed Interchange or Implemented Interchange for reliability purposes. Suggested modification follows: DELETE: “Request to modify a” ADD: Modified New definition: Interchange or Implemented Interchange for reliability purposes. The SDT is requested to modify M2 so it is consistent with R2. The current M2 language is: M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was created within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2) Suggested modification to M2. The Sink Balancing

Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was DELETE: “created” REPLACE with: “submitted” within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2) The SDT is requested to modify M3 so it is consistent with R3. The current M3 language is: The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a RFI was created reflecting that Interchange schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3) Suggested modification to M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a RFI was DELETE: “created” REPLACE with: “submitted” reflecting that Interchange schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)
Yes
No
Yes
No
The SDT is respectfully requested to clarify that a Pseudo-Tie is not a physical tie that actually exists.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
The SDT is requested to consider modifying the Reliability Adjustment Arranged Interchange definition. The current definition language is: Reliability Adjustment Arranged Interchange - Request to modify Confirmed Interchange or Implemented Interchange for reliability purposes. Suggested modification follows: DELETE: "Request to modify a” ADD: Modified New definition: Modified Confirmed Interchange or Implemented Interchange for reliability purposes.
Yes
Yes
Yes
No

In the Table of Compliance, R2 the current draft language is: A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours Suggested addition to Table of Compliance, R2 to make the Severe VSL consistent to the requirements: A deviation met or exceeded the criteria in Requirement R2 Parts 2.1-2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours ADD: is expected to persist.
Yes
Yes
Yes
Yes. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Don Schmit
Nebraska Public Power District
No
The standards still include RFI for pseudo ties. Ties are not interchange. I understand the desire to be able to curtail the transfer of energy on a pseudo tie, but we don’t require RFI for internal schedules utilizing Network Transmission Service, so not sure there is really much difference. I suggest the registration of the pseudo tie be included in the congestion management tools if that is really the concern.
No
I am concerned that the BA in which a DC line that crosses interconnection boundaries exists is not treated as a source/sink BA. The BA in which a DC line that crosses an interconnection boundary terminates, needs to have the ability to approve or deny these tags, based upon more than just the path between BA’s being correct. In addition, I am concerned that valid reasons for denying a reliability related interchange curtailment are not specified. We run into times when the DC tie trips and curtailments get denied by the sink (PJM). As a result the energy must be made up by the BA on the same side of the DC tie as the sink BA. The sink BA simply denies the curtailment even though the source has effectively tripped off-line. The BA that was not involved in the transaction is now on the hook to provide the MW immediately. This is not conducive to reliability and needs to be corrected.
No
Requirement 2.3 of INT-004 states that the LSE is responsible for maintaining the RFI for Reliability Adjustment requests. If the Pseudo-Ties are implemented through an agreed upon alternate congestion management approach (such as reporting market flows or generation-to-load flows to the IDC), the IDC will assign a relief obligation to the BA. The BA will redispatch its system to meet the relief obligation which may or may not involve a change to the pseudo-

tie output. In this instance, it is not appropriate to limit the pseudo-tie output in the ACE equation to a reliability cap if other generation is being redispatched to meet the relief obligation. Therefore it is recommended this requirement be removed.
Group
Dominion NERC Compliance Policy
Randi Heise
Yes
Throughout the entire Standard, Pseudo-Tie needs to be corrected to read as Pseudo-tie, as changed in the definition.
Yes
Attachment 1; footnote numbers 5 & 7 are listed in the table, but there are no corresponding footnotes at the bottom of the pages.
Yes
Throughout the entire Standard, Pseudo-Tie needs to be corrected to read as Pseudo-tie, as changed in the definition.
Yes
Throughout the entire Standard, Pseudo-Tie needs to be corrected to read as Pseudo-tie, as changed in the definition.
Yes
No
Yes
Yes
Dominion suggests in the Implementation Plan that Pseudo-Tie should be corrected to read as Pseudo-tie (as changed in the definition).
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Yes
No
While we can support the proposed revision to the term Operational Planning Analysis, for the reasons provided by SDT, we can do so only if corresponding changes are made to the term Real-time Assessment. We believe that Interchange needs to be in both definitions or neither definition. We also suggest that SDT consider revising the SAR and/or the Implementation Plans to more explicitly indicate that they are proposing revisions to the defined terms Operational Planning Analysis and Real-time Assessment which are used in (identify all standards where these terms are used).
Individual
Steven Wallace
Seminole Electric Cooperative, Inc.
Yes
R1 is ambiguous and open to interpretation. Recommend changing language to: R1 Each Load-Serving Entity that secures energy to serve Load via a Dynamic transfer shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Transfer. R1.1- A Request for Interchange shall be submitted as an on-time Arranged Interchange to the Sink Balancing Authority for all Dynamic Schedules. R1.2- A Request for Interchange shall only be submitted as an on-time Arranged Interchange to the Sink Balancing Authority for Dynamic Transfers using Pseudo-Ties if the Pseudo-tie has not been included in congestion management procedures, such as IDC model data or written / electronic agreements, which define the responsibilities associated with the dynamic transfer.
Yes
Requirement R4 as written is ambiguous and confusing and we suggest it be re-worded. Specifically, the language requiring the Sink BA to confirm the double negatives stated in the requirement, should be re-written to simplify.
No
Yes
R1 should not be qualified / limited to “a loss of resources covered by an energy sharing agreement”. Propose the following: ♣ The Balancing Authority that experiences a loss of a resource or Reliability Adjustment Arranged Interchange, requiring an immediate adjustment to scheduled interchange which will exceed 60 minutes in duration shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the start time of the event. Alternately, some effort should be made to clarify the intended meaning of “energy sharing agreement”, the use of which creates considerable ambiguity regarding the requirement and distinction from events NOT “covered by an energy sharing agreement”. R2 and R3 wording is ambiguous. Propose combining the two into the following: R2 Upon receiving a directive for a Reliability Adjustment Arranged Interchange to confirmed or implemented Interchange due to actual or anticipated reliability-related reasons, the Sink

Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange including the scheduled interchange is submitted within 60 minutes.
No
No
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Gordon Dobson-Mack
Powerex Corp.
Yes
Powerex has reviewed the latest draft of the Interchange Standards and considers these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are important and prevent entities that transact from providing false and misleading information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is implemented in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations. Powerex does not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards. Powerex believes that it is fundamentally important that all interchange be scheduled using e-Tags, and appropriately evaluated by the reliability entities listed on the e-Tag. Powerex agrees with the CISDT that Pseudo-Ties should be tagged so that those transactions are transparent and the appropriate reliability impacts are assessed. Ensuring that all interchange transaction are e-Tagged allows reliability tools, such as NERC IDC and WECC webSAS, to effectively manage congestion through curtailments in accordance with transmission priority. R1 as currently written is only applicable to LSEs that use Dynamic Transfer to serve load, and is not applicable to any PSE that submits a Dynamic Transfer. Powerex believes that the standard should be applied to PSEs that use Dynamic Transfers, whether it is used to serve load or provide imbalance service. The Dynamic

Transfer, regardless of its intended use, has the same level of impact to the BES, and applying this requirement only to a subset of Dynamic Transfers would not meet the intent and purpose of this standard. Powerex also suggests that when a forecast is not available that the RFI be submitted at the “expected maximum”. The standard is silent on the transmission requirements that would be used for the Dynamic Transfer. It is important that the transmission capacity required to support the transfer of dynamic flow be appropriately obtained, validated and verified prior to implementation. For example, dynamic schedules that are e-Tagged at an average MW level, but do not have sufficient transmission capacity above the average MW level may cause SOL exceedances when dynamic dispatches exceed the average MW indicated on the e-Tag. These types of scheduling issues result in cascading curtailments, which has impacts to other Generators and Loads that must accommodate because of the inaccurate scheduling of Dynamic Transfers. It is important that this standard clearly articulate that each dynamic transfer shall procure sufficient transmission to accommodate the maximum dynamic transfer.
Yes
Powerex has reviewed the latest draft of the Interchange Standards and considers these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are important and prevent entities that transact from providing false and misleading information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is implemented in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations. Powerex does not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards. There does not appear to be any requirement that prescribes, at a minimum, that an Interchange Transaction or Interchange Schedule must be submitted for energy that flows between Balancing Authorities. This should be the case, and a new requirement should be developed to reflect this. Otherwise some entities may choose not to submit certain interchange transactions even though it may affect adjacent Balancing Authorities and TSPs. This standard must prescribe at a minimum the verification and validations that must be performed during the reliability assessment by a BA and TSP. Those minimum requirements should not be prescribed in the Technical Guidance section of the standard because they would not be considered mandatory and could be ignored by Responsible Entities. It is imperative that this standard provide clear requirements that ensure BA and TSP are validating impacts, and not allowing transactions to flow that will cause issues within the interconnection. For example, a Source BA should validate and not allow a generator to schedule above and beyond its nameplate capacity to ensure accurate scheduling. Powerex believes that a Source BA will only perform these types of checks if there is a prescribed minimum requirement within a standard, and suggests that the CISDT provide the minimum set of validations. R1 and R2 does not hold the BA or TSP accountable to correctly approve or deny the interchange request the first time, and allows the entities to rectify the issue through curtailment of the interchange. Powerex believes that these

requirements should be modified to rectify a possible loophole that could lead to inefficient scheduling practices. M1 and M2 should measure the times the BA or TSP approves a request without proper verification or validation and then subsequently curtails the interchange once they realize the mistake. The BA or TSP should perform a thorough validation of an Arranged Interchange to avoid such instances which rectify BA or TSP mistakes. Powerex suggests that when a BA or TSP reevaluates a Confirmed Interchange that they note in the comments the reason for the reevaluation. For Attachment 1, there should be a reference point for the time that constitutes whether or not an Arranged Interchange is “on-time” or not. The previous Standard (INT-006-3) used to have the second column of the Timing Requirements table labeled as “IA Assigned Time Classification”. The new table heading for the second column is not assigned to an entity and states just “Time Classification” and should state “Sink BA Time Classification”. This will result in potential disputes as to who determines and classifies whether or not the RFI is “on-time”. An Entity should be assigned the responsibility to determine the correct time classification (On-Time, Late, etc). Powerex suggests that the Sink BA be the Responsible Entity, and that once the Sink BA assigns a classification that other approval entities should respect that classification.
Yes
Powerex has reviewed the latest draft of the Interchange Standards and considers these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are important and prevent entities that transact from providing false and misleading information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is implemented in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations. Powerex does not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards.
Yes
Powerex has reviewed the latest draft of the Interchange Standards and considers these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are important and prevent entities that transact from providing false and misleading information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is implemented in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations. Powerex does not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards. In R1, the term “energy sharing” is not capitalized and thus is open to interpretation, and this leaves the door open for entities to submit RFIs after the scheduling deadlines. In the original INT-010-1, this issue was dealt with

by describing the circumstance which this was allowed, specifically "…a loss of resources covered by an energy sharing agreement….". Either "energy sharing" needs to be defined, or the conditions to allow these modifications should be limited. Powerex suggests reverting back to the current INT-010-1 language use, "…a loss of resources covered by an energy sharing agreement….".
Yes
Yes
Powerex has reviewed the latest draft of the Interchange Standards and considers these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are important and prevent entities that transact from providing false and misleading information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is implemented in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations. Powerex does not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Group
Florida Municipal Power Agency
Frank Gaffney
Yes
FMPA thanks the SDT for their efforts. However, we believe that most of the requirements of the INT standards ought to be retired as being commercial in nature and duplicative of NAESB standards; and hence, should be retired in accordance with P81 recommendations and the

Independent Expert Review Panel recommendations. The requirements of INT-004 are duplicative with WEQ-004 and WEQ-005 and the standard should be retired in its entirety. If the SDT believes there are commercial considerations that ought to be included in the NAESB standards that are not currently within those standards, then the SDT ought to contact NAESB to initiate a modification to those standards. It is FMPA's opinion that the only reliability related requirements contained in the proposed INT standards are those that cause BA's to agree on composite interchange. The proposed standards should be reduced to just INT-009; the remainder of the proposed standards should be retired.
Yes
Please see FMPA comments to Question 1. INT-006 is commercial in nature, duplicative of NAESB standards, and should be retired in accordance with P81 recommendations and the Independent Expert Review Panel recommendations.
Yes
FMPA would have supported this standard but for the definitions. Please see our comments on definitions.
Yes
Please see FMPA comments to Question 1 The proposed INT-010 is duplicative of BAL standards (e.g., BAL-002) that already cause a BA to balance supply and demand for loss of a generator. This proposed standard simply contains commercial considerations for how such replacement is made and as such is not reliability based. As such, the standard should be retired in accordance with P81 recommendations and the Independent Expert Review Panel recommendations.
No
Please see FMPA comments to Question 1 The proposed INT-011 is duplicative of NAESB standards and is commercial in nature. As such, the standard should be retired in accordance with P81 recommendations and the Independent Expert Review Panel recommendations.
No
No
Since these are commercial definitions and not reliability based, the NAESB definitions should be used and no attempt to define it differently should be made. See WEQ-000 for NAESB definition.
No
Since these are commercial definitions and not reliability based, the NAESB definitions should be used and no attempt to define it differently should be made. See WEQ-000 for NAESB definition.
Yes
No
Since these are commercial definitions and not reliability based, the NAESB definitions should be used and no attempt to define it differently should be made. See WEQ-000 for NAESB definition.

No
Since these are commercial definitions and not reliability based, the NAESB definitions should be used and no attempt to define it differently should be made. See WEQ-000 for NAESB definition.
No
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No
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No
Since these are commercial definitions and not reliability based, the NAESB definitions should be used and no attempt to define it differently should be made. See WEQ-000 for NAESB definition.
Yes
Yes
Yes
No
INT-009 essentially describes inputs into the ACE equation, which are only Medium risk for 12 month rolling averages and 90% of clock ten minute periods during a month (BAL-001 R1 and R2) and Low (BAL-001 R3) VRFs; hence, each individual hourly input should be Low risk VRF. In addition, the BAL-001 standards adopt a non-zero defect approach (e.g., 90% of clock ten-minute interval during a month, 12 month rolling average) whereas the VSLs for INT-009 are zero-defect. This is inconsistent treatment of an input to the ACE equation versus the ACE equation itself.
Individual
Texas Reliability Entity
Texas Reliability Entity
Yes
1. Requirements R2.1 and R2.2: The phrase “and the deviation is expected to persist” is too open-ended. Suggest revising to “and the deviation is expected to persist for at least one additional hour.” Also, future hours may not meet the 10% or 25 MW criteria but should be included in the update. Consider adding to the end of 2.1 and 2.2 “even if the future hour deviations are less than the criteria”. 2. “Dynamic Transfer” is a defined term in the NERC Glossary. It should be capitalized in this standard and related materials.
Yes

1. These INT standards in general, and INT-011 in particular, do not appear to apply to intra-Balancing Authority Area transfers in the ERCOT region. Consider expressly excluding such transfers from the applicability of these standards in order to avoid future misunderstandings.
No
1. Requirement R1 VSL: Need to add language to cover the "curtail Confirmed Interchange" concept from the requirement. 2. Requirement R5 High VSL – As written it is unclear and ambiguous. As we understand the intent, this should say "notified less than all of the entities." The Severe VSL should say "did not notify any of the entities." Also after OR the Severe VSL should say "did not notify one or more entities in time…"
Individual
Catherine Wesley
PJM Interconnection
Yes
PJM does not support the applicability of R1 and R2 being assigned solely to Load-Serving Entities, as this appears to create a compliance gap for dynamic transfers that have been established without the involvement of an LSE. Consider a Variable Energy Resource that seeks to dynamically schedule its generation output from the Native BA to the Attaining BA without entering into an agreement with a specific LSE. In this example, which entity is responsible for R1 and R2? PJM does not support R1, as written. While PJM applauds the drafting team's attempt to allow either the tagging of Pseudo-Ties or their inclusion in a congestion management procedure, these alternatives are not equivalent from a reliability standpoint. A requirement to tag Pseudo-Ties ensures that all involved parties have visibility into the path and estimated magnitude of the transfer, including the congestion management tools currently in use. However, the alternative to include the Pseudo Tie in congestion management procedures via an alternate method fails to provide that same visibility. Further, the use of the term "congestion management procedure" implies that a local congestion management procedure established in the Native BA's footprint is sufficient to meet the requirement for not tagging a Pseudo Tie transfer that may span several Intermediate BAs. If the requirement is meant to ensure that all involved BAs and all congestion management procedures/tools benefit from added visibility, the existing language is insufficient. PJM encourages the drafting team to retain the flexibility provided in R1 while also taking steps to ensure that the alternatives to tagging provide equivalent benefit to all involved BAs and RCs. PJM does not support R2, as written, due to the applicability being granted solely to Load Serving Entities, which appears to introduce a compliance gap for dynamic transfers that do not involve LSEs. PJM supports R3, but asks the drafting team to consider adding further refinements to require the registration of Dynamic Schedules as well as Pseudo Ties. Additionally, PJM asks that a requirement be introduced that states a dynamic transfer is valid only if all parties have approved the dynamic transfer registration.
Yes

PJM supports the language in R1; however, the measures in M1 do not appear to cover R1.1 and R1.2. PJM suggests that the drafting team modify M1 to address these requirements. PJM supports the language in R2, R4 and R5. PJM supports the language in R3; however, there appears to be a potential typo in M3: " . . . or denied the request or that it communicated denial to the Reliability Coordinator" should read " . . . or denied the request and that it communicated denial to the Reliability Coordinator." PJM supports the revision to the Attachment 1 Timing Tables, but offers that in the draft that was reviewed, there appears to be a potential typo in the superscripts for columns A and C in both tables, as they superscripts do not match existing footnotes.
Yes
PJM supports the language in R1. PJM supports the language in R2, but asks the drafting team to consider providing accommodation for existing Pseudo-Ties. The effective date listed in the implementation plan does not provide sufficient time for the coordination required to modify existing Pseudo Ties. PJM does not support the language in R3, as written. Specifically, 1. The qualifier "if applicable" is ambiguous and suggests that there exist situations in which a Balancing Authority would not be required to coordinate with a Transmission Operator. If this is the case, the requirement should clearly outline these situations. 2. This requirement carries an unduly heavy compliance burden as there exist no options to streamline the coordination effort via agreements or technical solutions that mitigate the need for active coordination. BAs and TOPs should have an option to reduce their compliance burden in situations such as the TOP allowing the BA to directly control the HVDC tie via a telemetered control signal or when the TOP chooses to actively monitor E-Tag software and/or the BA's scheduling system to facilitate the operation of their HVDC facility.
Yes
PJM supports the language in R1, R2 and R3. PJM does not support R4, as written, for the following reasons: • It appears that Balancing Authorities have the leeway to take actions in an attempt to remain compliant that simultaneously leave the interconnection worse off. PJM suggests that Balancing Authorities should also be required to coordinate with their Adjacent Balancing Authorities as opposed to only requiring that the values included in their ACE equation never exceed the Confirmed Interchange value. • Further, this requirement makes no allowance for the implementation of a 10-minute straddle ramp without being considered non-compliant, nor does it allow for the physical ramp rates of generators that may be unable to reduce output before the Confirmed Interchange reduction takes effect. • Lastly, INT-004-3 R2 establishes a bandwidth that allows Confirmed Interchange to deviate from actual hourly integrated energy without requiring a tag update. Similarly, the MW value included in an ACE equation should be allowed to deviate from Confirmed Interchange within a certain bandwidth, even when the Confirmed Interchange results from a Reliability Adjustment Arranged Interchange.
Yes
No
Yes

Yes
PJM supports the revisions to the Pseudo Tie definition and recommends further modification of the definition to include reference that Pseudo Tied generation should be properly accounted for in a Balancing Authority's load calculation. The Native Balancing Authority must exclude that generation from their internal load calculation and the Attaining Balancing Authority must include that generation in their internal load calculation.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
PJM supports the new term Reliability Adjustment Arranged Interchange , but asks the drafting team to formally comment on the difference between this new definition and the existing definition Reliability Adjustment RFI and why it is necessary to replace the current term. This explanation was not apparent in the materials posted for review.
Yes
Yes
PJM supports the new term but asks the drafting team to formally comment on the rationale as to how this definition is materially different from the term Sink Balancing Authority and why it is necessary.
Yes
PJM assumes this question is specific to the new defined term Native Balancing Authority not Area. PJM supports the new term but asks the drafting team to formally comment on the rationale as to how this definition is materially different from the term Source Balancing Authority and why it is necessary.
No
PJM was unable to find mention of this revised term in the materials posted for comment.
Yes
Yes
Yes
Yes
Group
ACES Standards Collaborators
Jason Marshall

Yes
(1) We appreciate the improvements that drafting team has made to the standard but continue to believe many of the requirements are in fact business practices. For example, tagging Dynamic Schedules and Pseudo-ties and intra-BA transactions are commercial equity issues intended to ensure these transactions are curtailed equitably with other transmission service. RCs, BAs and TOPs have the ability to re-dispatch (which is essentially all a transmission service curtailment is) in other ways and must be able to do so for reliability purposes. Even FERC has recognized that the IDC and WECC USF are essentially congestion management tools and required the IRO-006-EAST standard to be modified to compel other tools such as redispatch to be used in conjunction with TLR curtailments to address IROL exceedances and violation. By NERC definition (both proposed and existing), a Dynamic Schedule is already correctly implemented in both the Attaining and Native Balancing Authorities. Thus, load, generation, and interchange will be balanced. The only reliability concern that is left is if the transmission system can handle the Dynamic Schedule. Since the vast majority of these Dynamic Schedules are grandfathered and, those, that are not will utilize firm transmission, the transmission system can certainly handle these Dynamic Schedules. This means that the only issue left is that it is a commercial equity and transparency issue. Even the purpose statement of the standard is clear that the purpose is to ensure that the transactions are accounted for in congestion management procedures appropriately. This is not a reliability concern and it should be transitioned to a NAESB business practice. (2) The interaction between R1 and R2 is not clear for the time period after the Request for Interchange has been submitted for the Dynamic Schedule but before the Dynamic Schedule has become Implemented Interchange. If the initial submittal of the Request for Interchange for the Dynamic Schedule is submitted at one MW level, transitions to Confirmed Interchange, and then the expected average MW profile changes (i.e. a unit derate) before the schedule becomes Implemented Interchange, is the LSE required to adjust the E-Tag? Clearly, if the Dynamic Schedule had transitioned to Implemented Interchange and the deviation exceeded thresholds in R2, the E-Tag would have to be adjusted but it is not clear that the Dynamic Schedule must be adjusted for changes before it transitions to Implemented Interchange. We recommend providing additional clarity of how R1 and R2 apply during the transition from Request for Interchange, Confirmed Interchange and Implemented Interchange in the Application Guidelines section of the standard. (3) INT-004-3 - The reliability impact of Dynamic Schedules will be addressed appropriately in the agreement established between the Attaining BA and the Native BA. The agreement will include items such as common metering points, implementation dates, testing requirements, etc. No additional reliability standards requirements are necessary for Dynamic Schedules. Furthermore, a NERC reliability guideline has already been written on dynamic transfers. We feel that there is enough technical guidance available to industry that could provide justification to FERC that additional requirements covering Dynamic Schedules are not needed. (5) Requirement R3 is clearly a business practice. It is a requirement to in essence follow a NAESB business practice to register Pseudo-Ties. While we agree the business practice should be followed for business and commercial reasons, it is simply not a reliability issue and should be removed. If the drafting team disagrees, it should pursue NERC taking

over the Electric Industry Registry from NAESB. The recent transition from the NERC TSIN registry to the NAESB EIR should provide justification that registering Pseudo-Ties should now be a function of NAESB. (6) Some of the information in the Guidelines and Technical Basis section is confusing or oversimplified and may be duplicated from existing NERC guidelines. For example, the table specifying the BA's obligation is based on whether a Dynamic Schedule or Pseudo-Tie is implemented shows that the Attaining BA or the Native BA is responsible for manual load shedding in an EEA. Clearly, it is the entity that is short that is responsible for shedding load. This is covered in other standards, such as EOP-003, and is not necessary here. Since this information is essentially a copy and paste from the guideline, perhaps a simple link to the guideline is all that is necessary. (7) Part 2.3 of INT-004 states that the LSE is responsible maintaining the RFI for Reliability Adjustment requests. INT-010 R4 seems to transfer that same activity to the BA role. We request to remove Requirement R4 from INT-010. If this is change is not made, we request that the application guidelines of each standard explain how these requirements complement one another.
Yes
(1) We appreciate the changes made to this standard and believe it is improved. However, we still have several issues with the standard. (2) The adjective "emergency" should be removed from requirement R1 because it causes confusion. The addition of this adjective to "Arranged Interchange" does nothing to change the requirement and may lead to confusion in registered entities trying to determine the purpose of delineating it. Each BA and TSP will still be required to approve or deny the Arrange Interchange regardless of whether it is an emergency Arranged Interchange or not. Thus, the adjective provides no clarification for what the requirement compels and will only lead to confusion. Please strike it from the requirement. (3) We disagree with the need for the BAs and TSPs to meet the timing requirements in column B of Attachment 1 per requirements R1 and R2 in an enforceable reliability standard. It is not necessary to meet timing requirements in column B for reliability and column B is, in fact, a business practice. Meeting timing requirements in Column D is all that is necessary for reliability. Consider if a BA or TSP fails to approve or deny an Arranged Interchange within two hours for a schedule submitted five hours before the ramp start. Reliability is not impacted if the schedule is ultimately approved in time for it to be implemented. The TSP or BA could take over four hours to approve and ultimately still transition the Arranged Interchange to Confirmed Interchange and then Implemented Interchange without any negative reliability impacts. Thus, column B timing is not ultimately what is needed for reliability. (4) INT-006-4 Part 1.2 – Denying Arranged Interchange or curtailing Confirmed Interchange because the scheduling path is invalid is a business practice issue. While we agree that this is a necessary task to comply with open access transmission tariffs, it is not a reliability issue but rather a business practice issue. Furthermore, this is a validation that should be performed automatically with tagging software. Thus, this part should be removed. (5) INT-006-4 Part 2.1 - Denying Arranged Interchange because the transmission path is invalid is a business practice issue and is not a reliability issue. It provides no indication for whether the transmission system can handle the Arranged Interchange. This should be moved to a NAESB business practice. Furthermore, this is something that should be automatically handled via the tagging software and is obviated by the entrenched nature of the software. (6) INT-006-4 Part 3.1 is

unnecessary and duplicative with the proposed NERC Board resolution for COM-002/COM-003 for developing the final standard. Part 3.1 does not reflect that an adjustment request may originate from other reliability entities such as BAs and may include arbitrary timelines. First, COM-002/COM-003 will compel three-part communication when preserving or changing the "state" of a Bulk Electric System Element. This could potentially compel communication of denial of Reliability Adjustment Arranged Interchange since curtailing a schedule could be viewed as changing the state. Second, Part 3.1 does not reflect that a reliability adjustment may be issued by a BA. It presumes that the adjustment comes from the RC by requiring communication to only the RC. Third, the basis for the need to communicate the denial within 10 minutes is not established or stated in the technical guidelines section. Without such basis, we can only assume it is arbitrary. We recommend striking Part 3.1 from the standard. (7) The clause "the time period specified in Attachment 1, Column B, has elapsed" should be struck from the third bullet of requirement R4. It is unnecessary as the only conditions necessary are that the Arranged Interchange has not been denied and it is not a Reliability Adjustment Arranged Interchange. (8) INT-006-4 Part 5.5 – PSE has been replaced in many parts of the proposed modifications to the INT standards with LSE. Part 6.4 compels notification of approvals and denials to the PSE but there is no companion part to compel notification to the LSE. Is this intended? (9) INT-006-4 – Guideline and Technical Basis – The first main bullet on page 16 and its sub-bullets need to be modified. The main bullet states that the LSE "that approves or denies Arranged Interchange". The LSE does neither. The LSE submits a Request for Interchange that becomes Arranged Interchange once the appropriate reliability entities receive and approve the request. The second associated sub-bullet in combination with the main bullet states that the LSE is responsible for communicating of the Arranged Interchange to the Sink Balancing Authority. Again, the LSE does not approve or deny so it cannot communicate approval or denial. (10) INT-006-4 – Guideline and Technical Basis – The first sub-bullet under the second main bullet on page 16 refers to communication that occurs between BAs, TSPs and PSEs. This is not consistent with the remainder of the proposal which focuses on replacing PSEs with LSEs.
Yes
(1) INT-009-2 R1 – This requirement is redundant with BAL-006-2 R4, which already requires Adjacent BAs to operate to a "common Net Interchange Schedule and Actual Net Interchange value" with opposite signs. Redundancy is one of the paragraph 81 criteria. Please remove the redundancy to avoid implementing requirements that will be retired later. (2) INT-009-2 R2 – This requirement also meets Paragraph 81 criteria because it is redundant with BAL-005-0.2b R12 and R12.3. The BAL-005 standard already requires the BAs to use a common metering point for Pseudo-Ties and Dynamic Schedules.
Yes
(1) INT-010-2 R4 uses the wrong interchange term. It states that each BA shall ensure the MW level from the Confirmed Interchange for Reliability Adjustment Arranged Interchange is not exceeded for the Dynamic Interchange Schedule or Pseudo-Tie established in the BA's ACE equation. However, it is the Implemented Interchange state in which the value is supposed to be entered into the ACE equation per the NERC Glossary Definition. Thus, we recommend

changing Confirmed Interchange to Implemented Interchange. (2) INT-010-2 R1 – There is a missing period at the end of the requirement.
No
(1) INT-011-1 addresses commercial equity issues and is a business practice. RCs, BAs, and TOPs are perfectly capable of working together to re-dispatch generation to address system constraints. The purpose of tagging these intra-BA transactions is to ensure they are included in congestion management procedures such as the IDC so that they are treated equitably with other interchange transactions which is essentially reflected in the purpose statement. While the primary purpose of the IDC is to manage congestion in an equitable fashion, the IDC and WECC USF are not reliability tools because they cannot relieve flows rapidly enough. In fact, FERC recognized this and required NERC to reflect this in the IRO-006 standards. IRO-006-EAST-1 R1 requires the RC to actually implement another action such as re-dispatch besides TLR to mitigate IROL exceedances and violations. Please strike this entire standard.
No
Please see our comments in our response to question 5. The entire standard should be deleted.
No
(1) “Net Interchange Scheduled” should be “Net Interchange Schedule” to match the definition in the NERC Glossary of Terms. There is an extra “d” at the end of the term. (2) There is no need to include the clause “that is updated in real time” in the definition. It only makes the definition longer, more confusing and could lead to ambiguity. Stating that it is updated in real-time implies that someone is actually taking action to update the schedule which is contrary to what is happening because the schedule is updated in the ACE equation automatically as the telemetered value changes. The description of a time-varying energy transfer is sufficiently clear and succinct to avoid ambiguity. Furthermore, if the energy transfer is time-varying it would change real-time.
No
(1) “Net Interchange Actual” should be “Net Actual Interchange”. The former is not in the NERC Glossary of Terms. (2)There is no need to include the clause “that is updated in real time” in the definition. It only makes the definition longer, more confusing and could lead to ambiguity. Stating that it is updated in real-time implies that someone is actually taking action to update the schedule which is contrary to what is happening because the schedule is updated in the ACE equation as the telemetered value changes. The description of a time-varying energy transfer is sufficiently clear and succinct to avoid ambiguity. Furthermore, if the energy transfer is time-varying it would change real-time.
No
(1) There are multiple definitions posted with slight variations. The definition as stated in INT-006 states that it is a “Balancing Authority Area whose Balancing Authority Area”. There is an extra Area in the definition. The definition as written in the implementation plan correctly does not include the first “Area”. However, it does include “that” which was struck in INT-006. These definitions need to be aligned. We believe the definition should be “A Balancing

Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff”.
No
(1) Since we believe that tagging of intra-BA schedules is performed for commercial and equity reasons and belongs in a business practice and not a standard, we do not support adding intra-BA scheduling to the definition. Reliability standards and corresponding definitions should not focus on market activities or interactions, as they do not relate to reliability of the Bulk Electric System.
No
(1) The definition should be simplified. Arranged Interchange can only become Confirmed Interchange once all required parties have approved it. Thus, there is no need to mention anything about parties not approving the interchange because it would not meet the definition. If a transaction is an Arranged Interchange, by definition, all required parties have approved it. Thus, please strike “no party has denied and”.
Yes
No
(1) By definition in the NERC Glossary, Interchange is an energy transfer that crosses BA boundaries. The proposed definition of Request for Interchange states that a bilateral Interchange may be within a single BA. This conflicts with the definition of Interchange.
Yes
Yes
No
(1) First, contrary to the name of the term, it is not actually Interchange but rather a request to modify Confirmed Interchange or Implemented Interchange. The name implies it is Interchange and this may cause confusion. (2) The name of the definition implies it is a type of Arranged Interchange which leads to confusion when reading INT-010 R2. Arranged Interchange is the state in which the sink BA has received Interchange information. Thus, if a reader assumes that Reliability Adjustment Arranged Interchange is a type of Arranged Interchange, INT-010 R2 becomes circular because it requires the Sink BA to ensure that Arranged Interchange is submitted which ultimately goes to the Sink BA by the definition of Arranged Interchange. Simply changing the name of Reliability Adjustment Arranged Interchange will avoid much of this confusion.
No

(1) Because INT-009 R1 is redundant with BAL-006 R4 and this is the only use of Composite Confirmed Interchange, we cannot support the definition. The requirement is unnecessary and obviates the need for the definition. (2) The Composite Confirmed Interchange definition is not clear. The definition could be the total aggregate Confirmed Interchange for a given BA or between BAs. Is it intended to have this flexibility? Since the definition is not limited to a single BA or any specific number of BAs, it could be interpreted as the aggregate of all Confirmed Interchange in an Interconnection which would be whatever Interchange is flowing across the DC ties. We recommend adding more details to the definition for clarity.
No
We suggest that “dynamic transfer” should be changed to Pseudo-Tie in the definition for clarity. After all, it is a Pseudo-Tie that changes the metered boundaries of the Balancing Authority Area. We also suggest changing “effective control boundaries” to “Balancing Authority Area” for clarity. BAA is the correct term and is more clear.
No
We suggest that “dynamic transfer” should be changed to Pseudo-Tie in the definition for clarity. After all, it is a Pseudo-Tie that changes the metered boundaries of the Balancing Authority Area. We also suggest changing “effective control boundaries” to “Balancing Authority Area” for clarity. BAA is the correct term and is more clear.
Yes
While we believe the proposed modification to the definition of OPA is unnecessary and provides no additional clarification for what is required, we can support the change if it addresses a FERC concern. We ultimately believe the change is unnecessary because the definition includes expected generation output levels. How could expected generation output levels not include the impact of Interchange? Interchange is implicitly included.
No
(1) The VSL for R2 is inconsistent with the requirement. The requirement states that the Confirmed Interchange associated with the Dynamic Schedule must be updated if the deviation is expected to persist. However, the VSL mentions nothing about the persistence of the deviation. From reading the VSL, one might conclude that the Confirmed Interchange is required to be updated even if the deviation is not expected to persist which is contrary to the requirement. (2) Because R3 is a business practice and should not be a requirement, we cannot support the VRF for this requirement. The requirement should be struck.
Yes
No
(1) Because R1 and R2 are redundant with BAL-006 R4 and BAL-005 R12 and R12.3 respectively, we cannot support the VRFs for these requirements. The requirements should be struck. (2) If INT-009-2 R1 persists, the VRF should be classified as a Lower VRF. The requirement is redundant with BAL-006 R4 which has a Lower VRF. FERC guidelines for VRFs would require similar requirements to have the same VRFs and FERC has already approved the VRF for BAL-006 R4.
Yes

Since the purpose of tagging intra-BA transactions is address commercial equity issues, we believe the requirement is a business practice and unnecessary for a reliability standard. Thus, we do not support the VRFs and VSLs.
Group
Bonneville Power Administration
Jamison Dye
Yes
• Definitions o Dynamic Schedule BPA recommends the drafting team remove the word “time-” from “A time-varying energy transfer that is update . . .” The term time-varying is inaccurate; the amount of energy varies while time does not. o Pseudo-Tie BPA recommends the drafting team remove the word “time-” from “A time-varying energy transfer that is update . . .” The term time-varying is inaccurate; the amount of energy varies while time does not. • 3rd bullet in Background BPA recommends the drafting team remove the extra “that” in the sentence. “. . . dynamic transfer and agree that that various responsibilities . . .” • Requirement 3 BPA requests that the drafting team provide clarification on what type of information needs to be registered for Pseudo-Tie.
Yes
• Requirement 2 BPA recommends the sub-requirements worded and numbered similar to R1.1 and R1.2 under R1 be added under R2: Change current draft R2.1 to R2.2 in regard to path and proper connectivity with adjacent TSP’s and insert a new R2.1 worded similar to R1.1 to address interchange magnitude. For example: 2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange. 2.2. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid. • Requirement 5 BPA requests clarification on how R5 will be implemented. Does the drafting team expect JESS/NAESB to make changes in the NAESB Tagging specification prior to the changes in the NERC Interchange standards? BPA recommends a 60-90 day bandwidth to allow entities to make necessary changes to meet this requirement. • VSL Section, R5 BPA requests clarification on the paragraph in High VSL column as it matches to the first paragraph in Severe VSL column. Should the word “OR” between the two risks description in the Severe VSL column be an “AND”? If no, how do NERC and WECC assess which severity level to apply when a Sink BA does not notify all of the entities listed in R5.1-5.5? • Attachment 1 – Timing Tables For clarification, BPA recommends modifying footnote 5 to read: “See NAESB WEQ004 Timing Tables, this table is a partial repeat of the NAESB Timing Table containing only items which are applicable to this standard.”
Yes
• Definitions o Dynamic Schedule BPA recommends the drafting team remove the word “time-” from “A time-varying energy transfer that is update . . .” The term time-varying is inaccurate; the amount of energy varies while time does not. o Pseudo-Tie BPA recommends

the drafting team remove the word “time-” from “A time-varying energy transfer that is update . . .” The term time-varying is inaccurate; the amount of energy varies while time does not. • R1 contains the term “Pseudo-tie”, whereas in Measure 1 and in VSL Section for R1 do not contain the term “Pseudo-tie”. BPA requests clarification on why the term “Pseudo-tie” in R1 but not in M1 and in the VSL for R1?
Yes
• Definitions o Dynamic Schedule • BPA recommends the drafting team remove the word “time-” from “A time-varying energy transfer that is update . . .” The term time-varying is inaccurate; the amount of energy varies while time does not. • Requirement 2 BPA requests clarification on how the drafting team expects R2 to be accomplished if the Sink BA is not the Transmission Operator. • General Considerations for Curtailments of Dynamic Transfers For clarification purposes, BPA recommends revising and moving the first sentence from the For Dynamic Schedule section to above the General Considerations for Curtailments of Dynamic Transfers section. “If Transmission Services between the source and sink BA is curtailed, then the allowable range of the magnitude of the schedules between them must be curtailed accordingly.” • For Dynamic Schedules: BPA recommends the term curtailment be modified to Reliability Adjustment Arranged Interchange in the For Dynamic Schedules section. • For Capacity Transactions: BPA recommends the drafting team consider adding the following subsection for Capacity Transactions, similar to the pseudo-tie statement as follows: If transmission services between the sink BA and the source BA are curtailed, then the allowable range of magnitude of the capacity transaction between them must be limited according to these constraints.
Yes
No
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Group
MRO NERC Standards Review Forum
Russel Mountjoy
No
No
No
Yes
R2.3 of INT-004 states that the LSE is responsible for maintaining the RFI for Reliability Adjustment requests. If the Pseudo-Ties are implemented through an agreed upon alternate congestion management approach (such as reporting market flows or generation-to-load flows to the IDC), the IDC will assign a relief obligation to the BA. The BA will redispatch its system to meet the relief obligation which may or may not involve a change to the pseudo-tie output. In this instance, it is not appropriate to limit the pseudo-tie output in the ACE equation to a reliability cap if other generation is being redispatched to meet the relief obligation. Therefore it is recommended this requirement be removed.
Yes
No
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Individual
Keith Morisette
Tacoma Power
Yes
R1, R2, and R3 should be replaced with a single requirement that captures the stated purpose, "To ensure that BAs implement the Interchange as agreed upon in the Interchange confirmation process and maintain the generation-to-load balance." Proposed single requirement: "R1. Each Balancing Authority that receives a non-dynamic Confirmed Interchange shall implement such Confirmed Interchange prior to the later of i) the start of the ramp; or ii) one minute after the non-dynamic Arranged Interchange is transitioned to Confirmed Interchange."
No
"Intra-Balancing Authority" is not a defined term and must be fully defined before using the term in a reliability standard.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Agree
SERC OC Review Group
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Yes
City of Austin dba Austin Energy (AE) respectfully requests consideration of the following comment: Requirement R4 contains a number of double negatives making it unnecessarily confusing. Please consider the following language: "Prior to transitioning an Arranged Interchange to Confirmed Interchange, each Sink Balancing Authority shall confirm the following conditions exist: (i) the time period specified in Attachment 1, Column B has elapsed and (ii) if it is a Reliability Adjustment Arranged Interchange, the Source Balancing Authority or

the Sink Balancing Authority associated with the Arranged Interchange has communicated its approval of the transition, or if it is not a Reliability Adjustment Arranged Interchange, (a) all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition and (b) no entity associated with the Arranged Interchange has communicated its denial of the transition.” We suggest the SDT format the foregoing language to aid in comprehension. We also ask that the SDT consider whether both (a) and (b) are truly necessary. If approval/denial is a binary choice, then satisfying (a), that is, having all BAs’ and TSPs’ approval, should be sufficient.
Yes
City of Austin dba Austin Energy (AE) supports Seattle City Light’s comments on this standard.
No
City of Austin dba Austin Energy (AE) supports Seattle City Light’s comments on this standard.
Yes
City of Austin dba Austin Energy (AE) supports Seattle City Light’s comments on this standard.
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City of Austin dba Austin Energy (AE) supports Seattle City Light’s comments on this standard.
City of Austin dba Austin Energy (AE) supports Seattle City Light’s comments on this standard.
No
The VSLs for INT-006-4 go straight to severe in many cases. We request that the SDT consider a more graduated approach to the VSLs.
Group
Colorado Spings Utilities
Kaleb Brimhall
No
Yes
Thank you standard drafting team for all of your efforts. Please revise the VSL levels for this standard. The Violation Severity Levels are inappropriately high and disproportional to the risk

to the Bulk Electric System.
No
No
No
No
No
No
No
No
No
No
No
No
No
No
No
No
No
No
No
Yes
Thank you standard drafting team for all of your efforts. Please revise the VSL levels for this standard. The Violation Severity Levels are inappropriately high and disproportional to the risk to the Bulk Electric System.
No
No
Individual
Kathleen Goodman
ISO New England Inc.
Agree
IRC SRC

Consideration of Comments

Project 2008-12 Coordinate Interchange Standards

The Coordinate Interchange Standard Drafting Team thanks all commenters who submitted comments on the drafts of INT-004-3, INT-006-4, INT-009-2, INT-010-2, and INT-011-1. These were posted for a 45-day public comment period from September 30, 2013 through November 13, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form.

The Coordinate Interchange Standard Drafting Team (CISDT) posted drafts of INT-004-3—Dyanmic Transfers, INT-006-4—Evaluation of Interchange Transactions, INT-009-2—Implementation of Interchange, INT-010-2—Interchange Initiation and Modification for Reliability, and INT-011-1—Intra-Balancing Authority Transaction Identification, along with nine revised definitions and four new definitions, for a 45-day comment and ballot period from September 30-November 15, 2013. There were 40 sets of comments, including comments from approximately 125 different people from approximately 89 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Support for the standards and definitions was generally high. The CISDT considered each of the comments submitted and has incorporated those that the team found to improve the quality of the standards.

INT-006-4, INT-009-2, INT-011-1, and most of the definitions (Pseudo-Tie, Adjacent Balancing Authority, Confirmed Interchange, Intermediate Balancing Authority, Sink Balancing Authority, Source Balancing Authority, Dynamic Schedule, Reliability Adjustment Arranged Interchange, Composite Confirmed Interchange, Attaining Balancing Authority, Native Balancing Area) earned stakeholder approval of 68% or more in the ballot, and the CISDT did not make any substantive changes to these standards or definitions based on stakeholder comments. Those standards and definitions will proceed to final ballot.

INT-004-3 received 67.35% approval in the ballot, but the CISDT was persuaded by stakeholder comments to make the following improvements to the standard:

- Changed the definitions of Request for Interchange (RFI) and Arranged Interchange to enhance clarity. (While the revised definitions of Arranged Interchange and Request for Interchange received 77.82% approval as part of the package of all definitions, the CISDT was persuaded by stakeholder comments to make improvements to the definitions to add clarity.

- Changed Load-Serving Entity to Purchasing-Selling Entity in the Applicability and Compliance sections and in R1 and R2 in response to industry comments.
- Made changes to the Background section to reflect changes to the standards.
- Added language in the R1 Rationale section to clarify that if no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.
- Added language in the R2 Rationale section to clarify that R2 does not preclude tags from being updated at any time, and that the requirement specifies conditions under which the tag must be updated.
- Made changes to R3 to clarify Balancing Authority obligations with respect to Pseudo-Ties included in the NAESB Electric Industry Registry publication.
- Modified the VSLs for R1, R2, and R3 to ensure that the language is consistent with the language in the requirements.
- Made minor changes to the definition of Sink Balancing Authority, Attaining Balancing Authority, Native Balancing Authority, and to the Background section and the R3 Rationale box for consistency or to correct typographical errors.
- Made various errata changes to ensure that capitalization of glossary terms and acronym usage is consistent across the standard.

INT-010-2 received 58.03% approval in the ballot, and the CISDT made the following improvements to address stakeholder comments:

- Added language and a Rationale box to R1 to provide clarity around "energy sharing agreement."
- Deleted R4 in response to industry comments that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit.
- Made minor changes to the Applicability Section, R1, R2, M2, and M3 for consistency or to correct typos.
- Modified the VSLs in R1 and R2 to ensure that the language is consistent with the language in the requirement.
- Made various errata changes to ensure that capitalization of glossary terms and acronym usage is consistent across the standard.

The revised two standards and two definitions are posted for a 45-day comment and ballot period from December 9, 2013-January 22, 2014, with a 10-day ballot period from January 10-22, 2014. **Note that all definitions have been stripped from the individual standards in favor of posting separate definition documents.**

All comments submitted may be reviewed in their original format on the standard's project page.

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, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Index to Questions, Comments, and Responses

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[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	Christina Koncz	PSEG Power LLC	NPCC	5
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
13.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebe TransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc,	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8
21.	Ayesha Sabouba	Hydro One Networks Inc,	NPCC	1
22.	Brian Shanahan	National Grid	NPCC	1
23.	Wayne Sipperly	New York Power Authority	NPCC	5
24.	Ben Wu	Orange and Rockland Utilities	NPCC	1
25.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
26.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
2.	Group	Paul Haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pawel Krupa	Seattle City Light	WECC	1
2.	Dana Wheelock	Seattle City Light	WECC	3
3.	Hao Li	Seattle City Light	WECC	4
4.	Mike Haynes	Seattle City Light	WECC	5
5.	Dennis Sismaet	Seattle City Light	WECC	6

				1	2	3	4	5	6	7	8	9	10
3.	Group	Greg Campoli	ISO/RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kathleen Goodman	ISO-NE	NPCC	
2.	Ben Li	IESO	NPCC	
3.	Terry Bilke	MISO	RFC	
4.	Charles Yeung	SPP	SPP	
5.	Ali Miremadi	CAISO	WECC	
6.	Al DiCaprio	PJM	RFC	
7.	Cheryl Mosley	ERCOT	ERCOT	

				1	2	3	4	5	6	7	8	9	10
4.	Group	Pamela Hunter	Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			Marketing										
No additional responses													
5.	Group	Ryan Millard	PacifiCorp					X					
No additional responses													
6.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Allan George	Sunflower Electric Power Corporation	SPP	1
3.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
4.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
5.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
6.	James Nail	City of Independence, MO	SPP	3
7.	Kevin Nincehelser	Westar Energy	SPP	1, 3, 5, 6
8.	Susan Quinn	Westar Energy	SPP	1, 3, 5, 6
9.	Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4
10.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6
11.	Marc Welsh	Westar Energy	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
7.	Group	Michael Lowman	Duke Energy	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

				1	2	3	4	5	6	7	8	9	10
8.	Group	Rene Free	SERC OC Review Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Thomas	IMEA	SERC	4
2.	Scott Homberg	TVA	SERC	1, 3, 5, 6
3.	Ken Clarke	PowerSouth	SERC	1, 5

				1	2	3	4	5	6	7	8	9	10
9.	Group	Randi Heise	Dominion NERC Compliance Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

1.	Louis Slade	Dominion	SERC	5, 6
2.	Connie Lowe	Dominion	RFC	6, 5
3.	MIke Garton	Dominon	NPCC	5, 6
4.	MIchael Crowley	Dominion	SERC	1, 3
5.	Randi Heise	Dominion	MRO	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach Utilities	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
2.	John Shaver	Southwest Transmission Cooperative	WECC	1
3.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
6.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Suzie Stone	Trans Commercial System Mgmt	WECC	1
2.	Wes Hutchison	Trans Commercial System Mgmt	WECC	1
3.	Mary Willey	Trans Commercial System Mgmt	WECC	1
4.	Andy Meyers	Power Scheduling Preschedule	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Russel Mountjoy	MRO NERC Standards Review Forum	X	X	X		X	X	X			

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Co.	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Coop	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	Midcontinent Independent System Operator	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Bos	Muscatine Power & Water	MRO	1, 3, 5, 6
14.	Scott Nickels	Rochester Public Utilities	MRO	4
15.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
16.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
17.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
14.	Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
15.	Group	Kaleb Brimhall	Colorado Spings Utilities	X		X		X	X				

No additional responses

				1	2	3	4	5	6	7	8	9	10
16.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
17.	Individual	Silvia Parada Mitchell	NextEra Energy/Florida Power and Light	X		X		X	X				
18.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
19.	Individual	Steve Alexanderson	Central Lincoln			X	X					X	

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
21.	Individual	Shirley Mayadewi	Manitoba Hydro	X		X		X	X				
22.	Individual	John Idzior	ReliabilityFirst Corporation										X
23.	Individual	Marie Knox	MISO		X								
24.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
25.	Individual	Chris Scanlon	Exleon Companies	X		X	X	X	X				
26.	Individual	Bill Fowler	City of Tallahassee, TAL			X							
27.	Individual	Jack Stamper	Clark Public Utilities	X									
28.	Individual	John Canavan	NorthWestern Energy	X									
29.	Individual	Scott Langston	City of Tallahassee	X									
30.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
31.	Individual	David Jendras	Ameren	X		X		X	X				
32.	Individual	Michael Falvo	Independent Electricity System Operator		X								
33.	Individual	Don Schmit	Nebraska Public Power District	X		X							
34.	Individual	Steven Wallace	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
35.	Individual	Gordon Dobson-Mack	Powerex Corp.						X				
36.	Individual	Texas Reliability Entity	Texas Reliability Entity										X
37.	Individual	Catherine Wesley	PJM Interconnection		X								
38.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
39.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
40.	Individual	Kathleen Goodman	ISO New England Inc.		X								

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

The CISDT thanks all commenters who supported other entities. Please see the responses to those comments below.

Organization	Agree	Supporting Comments of "Entity Name"
Associated Electric Cooperative, Inc. - JRO00088	Agree	SERC OC Review Group
Flathead Electric Cooperative, Inc.	Agree	I support the comments submitted by Steve Alexanderson with Central Lincoln / Western Small Entity Comment Group
City of Tallahassee, TAL	Agree	NextEra
Clark Public Utilities	Agree	Seattle City Light
City of Tallahassee	Agree	NextEra
Ameren	Agree	Ameren supports MISO's comments on the INT standards
ISO New England Inc.	Agree	IRC SRC
Seattle City Light		NextEra

1. **INT-004-3: Do you have any comments relating to INT-004-3? Please provide specific suggestions for improvement, including alternate language.**

Summary Consideration:

The CISDT thanks all commenters who submitted feedback. In response to industry feedback, the CISDT has modified the definitions of Request for Interchange and Arranged Interchange to enhance clarity, changed Load-Serving Entity to Purchasing-Selling Entity in all references, modified the Background section to reflect changes to the standard, modified the Rationale sections of both R1 and R2, modified R3 to clarify Balancing Authority obligations, modified the VSLs to ensure that the language is consistent with the language in the requirements, and made minor changes elsewhere for consistency (e.g., ensuring that all glossary terms are capitalized) or to correct typographical errors.

Organization	Yes or No	Question 1 Comment
Nebraska Public Power District	No	The standards still include RFI for pseudo ties. Ties are not interchange. I understand the desire to be able to curtail the transfer of energy on a pseudo tie, but we don't require RFI for internal schedules utilizing Network Transmission Service, so not sure there is really much difference. I suggest the registration of the pseudo tie be included in the congestion management tools if that is really the concern.
Response: Thank you for your comment. The standard only requires that RFIs for Pseudo-Ties are submitted if information about that Pseudo-Tie is not already included in congestion management procedure(s) via an alternate method.		
Northeast Power Coordinating Council	No	
PacifiCorp	No	
MRO NERC Standards Review Forum	No	
Colorado Spings Utilities	No	

Organization	Yes or No	Question 1 Comment
NIPSCO	No	
MidAmerican Energy	No	
Kansas City Power & Light	No	
Independent Electricity System Operator	No	
Seattle City Light	Yes	This proposed standard is a major change in the policy and how the Pseudo Ties have been used in the past. To date a number of Transmission Service Providers created some Business Practices (BP) requiring tagging of Pseudo Ties, there was no requirement in the NERC standards to do so. Seattle City Light does not feel there is a need for change at this time, and supports the position of NextEra regarding this proposed Standard. A second aspect of this change is the possible compliance implications. While the violation of Business Practices usually has some financial penalties these penalties do not have the same weight as violations of reliability standards. So implementation of this Standard as currently proposed will put entities in double jeopardy not only facing penalties for Business Practice violations but also NERC Standard violations. Seattle's preferred position is that all INT standards should be removed from the Reliability Standards and move to the Business Practices currently being implemented by NAESB, because they more closely represent commercial practices rather than reliability requirements. If this is not realistic and possible for the present INT development project (but may occur in the follow-up activities to the NERC Independent Expert Review) Seattle recommends the following language changes to the standard draft (new text in CAPS, cuts indicated by <deleted text>): 1. Add the following exclusion in R.1 R1. Each Load-Serving Entity that

Organization	Yes or No	Question 1 Comment
		secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method, OR ATTAINING AND SINK BALANCING AUTHORITIES ARE THE SAME. 2. Change R.2 as follows.R2. Each Load-Serving Entity that submits a Request For Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours <delete in order to support> WHEN congestion management procedures ARE IN EFFECT and if any one of the following occurs: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same Day Operations, Real Time Operations]2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than <deleted 10%> 30% for that hour and that deviation is expected to persist THROUGH THE HOURS WHEN CONGESTION MANAGEMENT PROCEDURES ARE IN EFFECT.2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than <deleted 25> 75 MW for that hour and that deviation is expected to persist THROUGH THE HOURS WHEN CONGESTION MANAGEMENT PROCEDURES ARE IN EFFECT.2.3. The Load-Serving Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange THROUGH THE HOURS WHEN CONGESTION MANAGEMENT PROCEDURES ARE IN EFFECT.

Response: Thank you for your comments.

1. **The CISDT disagrees, as your proposed revision would eliminate all Pseudo-Ties from the standard and that is a main part of the requirement.**

Organization	Yes or No	Question 1 Comment
2. The CISDT notes that it is important for the appropriate information to be in the tagging system at all times so that congestion management systems have the correct data with which to work. If the information is not updated until congestion management is in effect, the wrong curtailments or other congestion management steps may be taken.		
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	INT-004-3 R1 states, "Each Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method."Can the SDT clarify the reliability benefit for INT-004-3 R3, which requires the registration of Pseudo-Ties in the NAESB Electric Industry Registry prior to implementation? Why is registering pseudo-ties in the NAESB Electric Industry Registry required if R1 has been met?
Response: The CISDT originally drafted this requirement to have Pseudo-Ties registered to ensure that a Pseudo-Tie is properly established prior to its implementation. Transparency of all Pseudo-Ties ensures proper modeling by all impacted entities. Based on stakeholder feedback, the requirement was modified to be operational in nature: **R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures.**		
SPP Standards Review Group	Yes	Capitalize 'scheduled Interchange' in the Guidelines and Technical Basis Section to make it consistent with actual Interchange in the same section.
Response: Thank you for your comment. The SDT has made this change.		
Duke Energy	Yes	Duke Energy recommends combining R2.1 and R2.2 as follows for added clarity for when a Dynamic Schedule or Pseudo-Tie should be updated."R2.1. For Confirmed Interchange, when the actual hourly integrated energy deviates from the Confirmed Interchange by 25MW or 10%, whichever is greater, for that hour and that deviation is expected to

Organization	Yes or No	Question 1 Comment
		persist."
Response: Thank you for your comment. The CISDT is not persuaded that this language would improve the sub-requirements. Since most commenters support the current language, the CISDT has not changed it.		
SERC OC Review Group	Yes	The SDT is respectfully requested to clarify that a Pseudo-Tie is not a physical tie that actually exists. In the Table of Compliance, R2 the current draft language is: A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours Suggested addition to Table of Compliance, R2 to make the Severe VSL consistent to the requirements: A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours ADD: if expected to persist.
Response: Thank you for your comment. The CISDT notes that the definition includes the phrase "in the same manner as a Tie Line" which indicated that a Pseudo-Tie is not a physical tie line. The CISDT has made the suggested edit to the VSL for R2 for better consistency with the requirement language.		
Dominion NERC Compliance Policy	Yes	Throughout the entire Standard, Pseudo-Tie needs to be corrected to read as Pseudo-tie, as changed in the definition.
Response: Thank you for your comment. The reference has been changed to "Pseudo-Tie" for consistency through the standard documents.		
Florida Municipal Power Agency	Yes	FMPA thanks the SDT for their efforts. However, we believe that most of the requirements of the INT standards ought to be retired as being commercial in nature and duplicative of NAESB standards; and hence, should be retired in accordance with P81 recommendations and the

Organization	Yes or No	Question 1 Comment
		Independent Expert Review Panel recommendations. The requirements of INT-004 are duplicative with WEQ-004 and WEQ-005 and the standard should be retired in its entirety. If the SDT believes there are commercial considerations that ought to be included in the NAESB standards that are not currently within those standards, then the SDT ought to contact NAESB to initiate a modification to those standards. It is FMPA's opinion that the only reliability related requirements contained in the proposed INT standards are those that cause BA's to agree on composite interchange. The proposed standards should be reduced to just INT-009; the remainder of the proposed standards should be retired.
Response: Thank you for your comments. The CISDT has performed a thorough review of the INT standards and has proposed to retire a number of requirements that did not provide a discernible reliability benefit. The standards were posted in August with a specific question regarding the reliability benefit of each requirement and the majority of stakeholders agreed with the drafting teams recommendations. The Industry Expert Review Panel recommendations were considered by the CISDT as well. While the team agreed with many of their proposed retirements, there are a number of exceptions that the CISDT has noted in the Mapping Document for each requirement.		
ACES Standards Collaborators	Yes	(1) We appreciate the improvements that drafting team has made to the standard but continue to believe many of the requirements are in fact business practices. For example, tagging Dynamic Schedules and Pseudo-ties and intra-BA transactions are commercial equity issues intended to ensure these transactions are curtailed equitably with other transmission service. RCs, BAs and TOPs have the ability to re-dispatch (which is essentially all a transmission service curtailment is) in other ways and must be able to do so for reliability purposes. Even FERC has recognized that the IDC and WECC USF are essentially congestion management tools and required the IRO-006-EAST standard to be modified to compel other tools such as redispatch to be used in conjunction with TLR curtailments to address IROL exceedances and violation. By NERC definition (both proposed and existing), a Dynamic Schedule is already correctly implemented in both

Organization	Yes or No	Question 1 Comment
		the Attaining and Native Balancing Authorities. Thus, load, generation, and interchange will be balanced. The only reliability concern that is left is if the transmission system can handle the Dynamic Schedule. Since the vast majority of these Dynamic Schedules are grandfathered and, those, that are not will utilize firm transmission, the transmission system can certainly handle these Dynamic Schedules. This means that the only issue left is that it is a commercial equity and transparency issue. Even the purpose statement of the standard is clear that the purpose is to ensure that the transactions are accounted for in congestion management procedures appropriately. This is not a reliability concern and it should be transitioned to a NAESB business practice. (2) The interaction between R1 and R2 is not clear for the time period after the Request for Interchange has been submitted for the Dynamic Schedule but before the Dynamic Schedule has become Implemented Interchange. If the initial submittal of the Request for Interchange for the Dynamic Schedule is submitted at one MW level, transitions to Confirmed Interchange, and then the expected average MW profile changes (i.e. a unit derate) before the schedule becomes Implemented Interchange, is the LSE required to adjust the E-Tag? Clearly, if the Dynamic Schedule had transitioned to Implemented Interchange and the deviation exceeded thresholds in R2, the E-Tag would have to be adjusted but it is not clear that the Dynamic Schedule must be adjusted for changes before it transitions to Implemented Interchange. We recommend providing additional clarity of how R1 and R2 apply during the transition from Request for Interchange, Confirmed Interchange and Implemented Interchange in the Application Guidelines section of the standard. (3) INT-004-3 - The reliability impact of Dynamic Schedules will be addressed appropriately in the agreement established between the Attaining BA and the Native BA. The agreement will include items such as common metering points, implementation dates, testing requirements, etc.

Organization	Yes or No	Question 1 Comment
		No additional reliability standards requirements are necessary for Dynamic Schedules. Furthermore, a NERC reliability guideline has already been written on dynamic transfers. We feel that there is enough technical guidance available to industry that could provide justification to FERC that additional requirements covering Dynamic Schedules are not needed. (5) Requirement R3 is clearly a business practice. It is a requirement to in essence follow a NAESB business practice to register Pseudo-Ties. While we agree the business practice should be followed for business and commercial reasons, it is simply not a reliability issue and should be removed. If the drafting team disagrees, it should pursue NERC taking over the Electric Industry Registry from NAESB. The recent transition from the NERC TSIN registry to the NAESB EIR should provide justification that registering Pseudo-Ties should now be a function of NAESB. (6) Some of the information in the Guidelines and Technical Basis section is confusing or oversimplified and may be duplicated from existing NERC guidelines. For example, the table specifying the BA's obligation is based on whether a Dynamic Schedule or Pseudo-Tie is implemented shows that the Attaining BA or the Native BA is responsible for manual load shedding in an EEA. Clearly, it is the entity that is short that is responsible for shedding load. This is covered in other standards, such as EOP-003, and is not necessary here. Since this information is essentially a copy and paste from the guideline, perhaps a simple link to the guideline is all that is necessary. (7) Part 2.3 of INT-004 states that the LSE is responsible maintaining the RFI for Reliability Adjustment requests. INT-010 R4 seems to transfer that same activity to the BA role. We request to remove Requirement R4 from INT-010. If this is change is not made, we request that the application guidelines of each standard explain how these requirements complement one another.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. 1. The CISDT has performed a thorough review of the INT standards and has proposed to retire a number of requirements that did not provide a discernible reliability benefit. The standards were posted in August with a specific question regarding the reliability benefit of each requirement and the majority of stakeholders agreed with the drafting teams recommendations. The Industry Expert Review Panel recommendations were considered by the CISDT as well. While the team agreed with many of their proposed retirements, there are a number of exceptions that the CISDT has noted in the Mapping Document for each requirement. 2. The CISDT believes that the tag should be updated whenever you have sufficient information that warrants a revision. The requirement does not preclude the tag from being updated at anytime, but there is a point in time where the information must be updated (per R2). We have added a Rationale for R2 to clarify this. 3. The CISDT has performed a thorough review of the INT standards and has proposed to retire a number of requirements that did not provide a discernible reliability benefit. The standards were posted in August with a specific question regarding the reliability benefit of each requirement and the majority of stakeholders agreed with the drafting teams recommendations. The Industry Expert Review Panel recommendations were considered by the CISDT as well. While the team agreed with many of their proposed retirements, there are a number of exceptions that the CISDT has noted in the Mapping Document for each requirement. 5. R3 has been revised to be operational in nature. Rather than requiring the Balancing Authority to register a Pseudo-Tie, they are required to ensure that it is registered prior to implementation: R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures. 6. We note that a link to the document is on Section F of the standard. We will retain the language in the Guidelines and Technical Basis section as it adds value to the standard. 7. The CISDT has removed R4 from INT-010. A Reliability Adjustment Arrange Interchange (RAAI) that is approved does not require an update to a Confirmed Interchange (CI). A RAAI that is approved should impact how the Attaining and Native BA implement a dynamic transfer in real-time to honor the MW amount resulting from the RAAI. An update to a CI which impacts future time periods is only required when directed by the Transmission Operator in the Western Interconnection or the		

Organization	Yes or No	Question 1 Comment
Reliability Coordinator in all other Interconnections.		
Bonneville Power Administration	Yes	o Definitions o Dynamic Schedule BPA recommends the drafting team remove the word "time-" from "A time-varying energy transfer that is update . . ." The term time-varying is inaccurate; the amount of energy varies while time does not. o Pseudo-TieBPA recommends the drafting team remove the word "time-" from "A time-varying energy transfer that is update . . ." The term time-varying is inaccurate; the amount of energy varies while time does not. o 3rd bullet in Background BPA recommends the drafting team remove the extra "that" in the sentence. ". . . dynamic transfer and agree that that various responsibilities . . ." o Requirement 3BPA requests that the drafting team provide clarification on what type of information needs to be registered for Pseudo-Tie.
Response: Thank you for your comments. The CISDT disagrees with the first two bullets, as the term "time-varying" is an adjective relating to the energy transfer. The CISDT agrees with the removal of the extraneous "that" in the Background section. With respect to R3, additional information on the information needed to register a Pseudo-Tie will be established during the NAESB process. R3 has been revised to be operational in nature. Rather than requiring the Balancing Authority to register a Pseudo-Tie, they are required to ensure that it is registered prior to implementation: **R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures.**		
NextEra Energy/Florida Power and Light	Yes	This standard appears to be more directed at correcting a perceived inequity in congestion management procedures than in promoting or ensuring real-time reliability. If the industry believes congestion

Organization	Yes or No	Question 1 Comment
		management procedures require enhancements related to Dynamic Schedules and Pseudo-Ties, there are much more efficient and less burdensome means to achieve this goal than to put in place this reliability standard. For example, NERC could require a LSE or BA to post near real-time flows for Dynamic Schedules and Pseudo-ties on System Data Exchange (SDX) so that congestion management procedures could have access to more accurate current-hour data than anything provided in this burdensome and administrative standard, which also means it should be more closely considered under the paragraph 81 criteria. Issues with the individual requirements are as follows: R1 requires a LSE to submit an on-time RFI that will never be implemented in a real-time EMS system and in no way impacts real-time flows and thus, reliability. It is an administrative function and provides no actual real-time reliability benefits, and, thus, should be deleted under paragraph 81 criteria. R2 does not require a LSE to do anything, regardless of the size of a deviation, if the LSE does not expect the same deviation to persist. Updating future hours based on a deviation last hour does nothing for the current hour real-time reliability, which is what the congestion management procedures are intended to deal with. Additionally, these requirements needlessly expose a LSE to potential violations and fines if an auditor chooses, well after the fact, to second guess the LSE's decision about not updating a RFI that never gets implemented in an EMS. R3 is putting the cart before the horse. It requires a BA to register a Pseudo-Tie in a non-existing registry proposed by this requirement to be administered by NAESB, an entity not responsible for reliability, in order to support congestion management procedures. It is both unclear and hard to fathom how requiring a BA to resister a Pseudo-Tie in a registry does anything for reliability when no reliability standard requires any entity to

Organization	Yes or No	Question 1 Comment
		utilize this data for anything. Further, this requirement is not just an administrative task, but a future administrative task that provides no discernible reliability benefits, and, thus, should be deleted under paragraph 81 criteria.
Response: The CISDT has performed a thorough review of the INT standards and has proposed to retire a number of requirements that did not provide a discernible reliability benefit. The standards were posted in August with a specific question regarding the reliability benefit of each requirement and the majority of stakeholders agreed with the drafting teams recommendations. The Industry Expert Review Panel recommendations were considered by the CISDT as well. While the team agreed with many of their proposed retirements, there are a number of exceptions that the CISDT has noted in the Mapping Document for each requirement. **R1: The CISDT disagrees as Dynamic Schedules and Pseudo-Ties are included in appropriate terms in ACE equation and therefore can impact reliability. The applicability of R1 was revised to be the Purchasing-Selling Entity.** **R2: R2 is intended for the PSE (applicability changed from LSE) to update tags when they know that the existing tag is incorrect and will remain that way.** **R3: R3 has been revised to be operational in nature. Rather than requiring the Balancing Authority to register a Pseudo-Tie, they are required to ensure that it is registered prior to implementation:** **R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures.**		
American Electric Power	Yes	Pseudo-Ties and Dynamic Schedules are handled by two different Functional Entities. Dynamic Schedules are managed by PSE's while Pseudo-Ties require input from LSE's. We recommend that this work be separated from R1 into different requirements and that PSE be added to the Applicability section. We would like the project team to provide some insight on why definitions

Organization	Yes or No	Question 1 Comment
		for were needed for Attaining Balancing Authority and Native Balancing Authority rather than utilizing Source Balancing Authority and Sink Balance Authority. Definition of Arranged Interchange - We recommend the definition be changed to the following: The state where the Interchange Sink Balancing Authority has received the RFI or intra-Balancing Authority transfer information (initial or revised). Our negative vote on this standard is primarily driven by our recommendation that the PSE be added to the Applicability section.
Response: The CISDT thanks you for your comments. **1 Based on your and other's comments, the CISDT has changed the applicable entity for Requirements R1 and R2 to PSE as is the case in the existing standard.** **2 This definition is used to align more with the terms used in the NAESB standards.** **3 Based on your and other's comments, the CISDT has revised this definition to: "The state where a Request for Interchange (initial or revised) has been submitted for approval."**		
Central Lincoln	Yes	Suggest changing "4.2. Load-Serving Entity" to "4.2. Load-Serving Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie." This better matches the trend to more explicitly state the applicability within the applicability section.
Response: Thank you for your comment. All references to "Load-Serving Entity" have been changed to "Purchasing-Selling Entity."		
Manitoba Hydro	Yes	(a) Manitoba Hydro does not agree with the INT-004-3 Draft 3 changes (issued September 17, 2013) to R1 and R2. The CISDT had previously incorporated stakeholder's suggestions in both Draft 1 (issued November 10, 2009) and Draft 2 (issued July 12, 2013) to address tagging Dynamic Transfers in the absence of a forecast. Subsequently in Draft 3 (after the

Organization	Yes or No	Question 1 Comment
		30-day informal comment period following Draft 2) the CISDT, in addressing a stakeholder's concern with the word 'expected' in the term "expected maximum", made modifications to both R1 and R2, including deleting in its entirety the bulleted statement which contained the word that were the subject of the stakeholder comment. Such modification indirectly implies a forecast is possible. Manitoba Hydro would respectfully like to point out that there are instances in which an LSE cannot forecast Dynamic Transfers, such as market transactions were ISOs dispatch energy and/or ancillary services based on economic price signals. In such instances tagging at a maximum value is appropriate to ensure reliability. Currently the language of Requirement R1 and R2 is not sufficiently clear to indicate to the LSE what value should properly be included in the energy profile for the Dynamic Transfer tag. The Rationale Statement (which will be removed from the requirement in any event once the standard is finalized) refers only to a scenario where a forecast is available, and leaves it open to interpretation what value should be included where a forecast is not available. Our preference is to see clear direction given to the Responsible Entity in the language of the standard itself as to the appropriate values for inclusion in Dynamic Transfer tags. As a solution, Manitoba Hydro suggests (i) returning to the Draft 1 / Draft 2 language for R1 and R2, or in the alternative, (ii) returning to the Draft 1/Draft 2 language for R1 and R2 but in order to remove confusion, replace the term "expected maximum" in R1 with "maximum" or "capped maximum". (b) The term "Dynamic Transfer" is used in the two new proposed definitions. Dynamic Transfer is a defined term in the NERC Glossary - is it meant to be capitalized here? (c) The definitions seem to indicate that Pseudo-Tie has a lower case 't'. However, throughout the standards, Pseudo-Tie has a capital 'T'. (This applies to all the Interchange Standards reviewed here).

Organization	Yes or No	Question 1 Comment
		(d) M1 - Words seem to be missing from the first sentence. Sentence should end with 'Pseudo-ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-tie." (e) M3 - includes the words 'prior to its implementation' which do not appear in the requirement itself.
Response: Thank you for your comments. **(a) The CISDT has added this concept to the Rationale for Requirement R1: If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.** **(b) Yes, the term should be capitalized. The team has made that change.** **(c) "Pseudo-Tie" should be all uppercase, and that has been made consistent throughout the standards.** **(d) The CISDT agrees and has made that change.** **(e) The CISDT agrees and has made that change.**		
ReliabilityFirst Corporation	Yes	ReliabilityFirst votes in the affirmative because the modifications to this standard help to ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures. Even though ReliabilityFirst votes in the affirmative, we offer the following for consideration: 1. Requirement R1 a. ReliabilityFirst requests further clarification on the meaning of the term "on-time" which proceeds the term "Arranged Interchange". Does the "on-time" term have a specific meaning within the context of the standard and if so, ReliabilityFirst recommends making it a defined term.
Response: Thank you for your comment. The term "on-time" is addressed in the timing tables contained in INT-006.		
Exleon Companies	Yes	R1 requires a LSE to submit an on-time RFI that will not be implemented in a real-time EMS system and will not impact reliability. It appears to be an

Organization	Yes or No	Question 1 Comment
		administrative function. R2 does not appear to require a LSE to do anything impacting operations. R3 requires a BA to register a Pseudo-Tie in a non-existing registry proposed by this requirement to be administered by NAESB, an entity not responsible for reliability. This seems unrelated to reliability and premature.
Response: The CISDT has performed a thorough review of the INT standards and has proposed to retire a number of requirements that did not provide a discernible reliability benefit. The standards were posted in August with a specific question regarding the reliability benefit of each requirement and the majority of stakeholders agreed with the drafting teams recommendations. The Industry Expert Review Panel recommendations were considered by the CISDT as well. While the team agreed with many of their proposed retirements, there are a number of exceptions that the CISDT has noted in the Mapping Document for each requirement. **R1: The CISDT disagrees as Dynamic Schedules and Pseudo-Ties are included in appropriate terms in ACE equation and therefore can impact reliability. The applicability of R1 was revised to be the Purchasing-Selling Entity.** **R2: R2 is intended for the PSE (applicability changed from LSE) to update tags when they know that the existing tag is incorrect and will remain that way.** **R3: R3 has been revised to be operational in nature. Rather than requiring the Balancing Authority to register a Pseudo-Tie, they are required to ensure that it is registered prior to implementation:** **R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures.**		
NorthWestern Energy	Yes	We believe the VSL for R2 should be low, not severe because this would not have a negative impact on BES reliability because the values are not included in the ACE equation.
Response: Thank you for your comment. VRFs measure the impact to reliability of violating a specific requirement and VSLs		

Organization	Yes or No	Question 1 Comment
measure the degree to which a standard was violated. A standard can have a Lower VRF, because violating it would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, and still have Severe VSL, indicating that the requirement is pass/fail. As the VSL Guidelines state, "If the required performance cannot be broken down to categorize degrees of noncompliant performance that at least partially meet the reliability objective of the requirement, any noncompliance with the requirement will have only one VSL – Severe."		
Seminole Electric Cooperative, Inc.	Yes	R1 is ambiguous and open to interpretation. Recommend changing language to: R1 Each Load-Serving Entity that secures energy to serve Load via a Dynamic transfer shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Transfer. R1.1- A Request for Interchange shall be submitted as an on-time Arranged Interchange to the Sink Balancing Authority for all Dynamic Schedules. R1.2- A Request for Interchange shall only be submitted as an on-time Arranged Interchange to the Sink Balancing Authority for Dynamic Transfers using Pseudo-Ties if the Pseudo-tie has not been included in congestion management procedures, such as IDC model data or written / electronic agreements, which define the responsibilities associated with the dynamic transfer.
Response: Thank you for your comment. The CISDT and most stakeholders support the current language. Besides changing Load-Serving Entity to Purchasing-Selling Entity, no changes have been made to R1.		
Powerex Corp.	Yes	Powerex has reviewed the latest draft of the Interchange Standards and considers these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are important and prevent entities that transact from providing false and misleading information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is

Organization	Yes or No	Question 1 Comment
		implemented in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations. Powerex does not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards. Powerex believes that it is fundamentally important that all interchange be scheduled using e-Tags, and appropriately evaluated by the reliability entities listed on the e-Tag. Powerex agrees with the CISDT that Pseudo-Ties should be tagged so that those transactions are transparent and the appropriate reliability impacts are assessed. Ensuring that all interchange transaction are e-Tagged allows reliability tools, such as NERC IDC and WECC webSAS, to effectively manage congestion through curtailments in accordance with transmission priority. R1 as currently written is only applicable to LSEs that use Dynamic Transfer to serve load, and is not applicable to any PSE that submits a Dynamic Transfer. Powerex believes that the standard should be applied to PSEs that use Dynamic Transfers, whether it is used to serve load or provide imbalance service. The Dynamic Transfer, regardless of its intended use, has the same level of impact to the BES, and applying this requirement only to a subset of Dynamic Transfers would not meet the intent and purpose of this standard. Powerex also suggests that when a forecast is not available that the RFI be submitted at the “expected maximum”. The standard is silent on the transmission requirements that would be used for the Dynamic Transfer. It is important that the transmission capacity required to support the transfer of dynamic flow be appropriately obtained, validated and verified prior to implementation. For example, dynamic schedules that are e-Tagged at an average MW level, but do not have sufficient transmission capacity above the average MW level may cause SOL exceedances when dynamic dispatches exceed the average MW indicated on the e-Tag. These types of scheduling issues result in cascading curtailments, which has impacts to other Generators and Loads that must

Organization	Yes or No	Question 1 Comment
		accommodate because of the inaccurate scheduling of Dynamic Transfers. It is important that this standard clearly articulate that each dynamic transfer shall procure sufficient transmission to accommodate the maximum dynamic transfer.
Response: Thank you for your comment. The CISDT put the "expected maximum" language in the Rationale. Transmission requirements for Interchange are addressed in NAESB Business Practices and approved tariff.		
Texas Reliability Entity	Yes	1. Requirements R2.1 and R2.2: The phrase "and the deviation is expected to persist" is too open-ended. Suggest revising to "and the deviation is expected to persist for at least one additional hour." Also, future hours may not meet the 10% or 25 MW criteria but should be included in the update. Consider adding to the end of 2.1 and 2.2 "even if the future hour deviations are less than the criteria". 2. "Dynamic Transfer" is a defined term in the NERC Glossary. It should be capitalized in this standard and related materials.
Response: Thank you for your comment. **1. The CISDT disagrees, as the proposed language indicates that the tag must be updated every hour regardless of the deviation amount.** **2. The CISDT agrees and has made this revision.**		
PJM Interconnection	Yes	PJM does not support the applicability of R1 and R2 being assigned solely to Load-Serving Entities, as this appears to create a compliance gap for dynamic transfers that have been established without the involvement of an LSE. Consider a Variable Energy Resource that seeks to dynamically schedule its generation output from the Native BA to the Attaining BA without entering into an agreement with a specific LSE. In this example, which entity is responsible for R1 and R2? PJM does not support R1, as written. While PJM applauds the drafting

Organization	Yes or No	Question 1 Comment
		team's attempt to allow either the tagging of Pseudo-Ties or their inclusion in a congestion management procedure, these alternatives are not equivalent from a reliability standpoint. A requirement to tag Pseudo-Ties ensures that all involved parties have visibility into the path and estimated magnitude of the transfer, including the congestion management tools currently in use. However, the alternative to include the Pseudo Tie in congestion management procedures via an alternate method fails to provide that same visibility. Further, the use of the term "congestion management procedure" implies that a local congestion management procedure established in the Native BA's footprint is sufficient to meet the requirement for not tagging a Pseudo Tie transfer that may span several Intermediate BAs. If the requirement is meant to ensure that all involved BAs and all congestion management procedures/tools benefit from added visibility, the existing language is insufficient. PJM encourages the drafting team to retain the flexibility provided in R1 while also taking steps to ensure that the alternatives to tagging provide equivalent benefit to all involved BAs and RCs. PJM does not support R2, as written, due to the applicability being granted solely to Load Serving Entities, which appears to introduce a compliance gap for dynamic transfers that do not involve LSEs. PJM supports R3, but asks the drafting team to consider adding further refinements to require the registration of Dynamic Schedules as well as Pseudo Ties. Additionally, PJM asks that a requirement be introduced that states a dynamic transfer is valid only if all parties have approved the dynamic transfer registration.
Response: Thank you for your comments. **Applicability: The CISDT has revised the applicability for R1 and R2 to Purchasing-Selling Entity.**		

Organization	Yes or No	Question 1 Comment
R1 the use of "congestion management procedures" in R1 is to differentiate between Interconnections. For example, the Eastern Interconnection uses TLR while the Western Interconnection uses a different term. R2 The CISDT has revised the applicability for R2 to Purchasing-Selling Entity. R3 has been revised to be operational in nature. Rather than requiring the Balancing Authority to register a Pseudo-Tie, they are required to ensure that it is registered prior to implementation: R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures.		
City of Austin dba Austin Energy	Yes	City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Thank you. Please see the response to Seattle City Light.		
MISO	Yes	

2. **INT-006-4: Do you have any comments relating to INT-006-4? Please provide specific suggestions for improvement, including alternate language.**

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT did not make any substantive changes to INT-006-4, and it will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 2 Comment
Seattle City Light	No	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
SPP Standards Review Group	No	
MRO NERC Standards Review Forum	No	
American Electric Power	No	
Central Lincoln	No	

Organization	Yes or No	Question 2 Comment
NIPSCO	No	
s	No	
MidAmerican Energy	No	
Exleon Companies	No	
NorthWestern Energy	No	
Kansas City Power & Light	No	
Independent Electricity System Operator	No	
Northeast Power Coordinating Council	Yes	It isn't clear in what manner the entities listed in 5.1 through 5.5 shall be notified by the BA of the Confirmed Interchange.
Response: Thank you for your comment. The CISDT expects that this will be accomplished through the e-tagging system or, in its absence, the responsible entity's back up procedures.		
ISO/RTO Standards Review Committee	Yes	R3 (Measurement)Will evidence that the BA communicated to the E-tag system, which is then delivered to the RC, within 10 minutes of the denial of the Reliability Adjustment Arranged Interchange suffice as meeting Requirement R3.1? If not, please provide clarification as to why this will not suffice and what additional evidence would be needed.R5. Per FERC Order 764, an RFI may be submitted 20-minutes in advance of start time. Per NERC Standards, that RFI has a 10-minute approval window. If the Ramp Duration of the RFI is 20-minutes, normal system communication may lend itself to a violation of this standard. Recommend the SDT consider the timing implication and revise the requirement so that it is not a zero exceptions requirements.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. With respect to R3, the CISDT concurs that tagging evidence will suffice. With respect to R5, the CISDT notes that, under your scenario, the tag would be considered late per the timing tables and implementation will be less than 3 minutes after receipt of Confirmed Interchange. This example is exempt from Requirement R5.		
PacifiCorp	Yes	Requirement R2.1: It is unclear to PacifiCorp why the drafting team has only referenced "Proper connectivity of adjacent TSPs" that is "invalid" as the criteria required for a denial or curtailment. Highlighting "proper connectivity of adjacent Transmission Service Providers" seems to indicate that connectivity is the only validation that occurs (which is inherently misleading). To align more with the assessment TSPs are required to perform, PacifiCorp suggests adding additional validations where a denial or curtailment would occur (e.g., physical path, transmission profile, transmission limit, valid OASIS reservation, etc.). If the intent of the requirement is to more broadly cover all criteria that would result in the denial or curtailment of the Arranged Interchange and Confirmed Interchange (rather than to reference an exhaustive list of criteria), connectivity should be removed from the requirement or cited as an example. Otherwise, a denial or curtailment for something other than what is explicitly referenced in the requirement could be interpreted as an improper denial or curtailment. Requirement R3.1: It is unclear to PacifiCorp what the drafting team has intended the word "communicate" to mean under R3.1, as all approvals and denials associated with a Reliability Adjustment Arranged Interchange are "communicated" to the Reliability Coordinator via e-tagging. Additionally, all reasons for a denial are indicated on an e-tag. PacifiCorp would like to understand the rationale for requiring additional communication and the specific method of communication which is required under R3.1.
Response: Thank you for your comment. With respect to R2.1, The CISDT wrote the requirement to provide clarity regarding denial of a tag for specific situations. This includes the minimum set of conditions under which the tag should be denied. The reasons for denial are not comprehensive and additional conditions may exist. With respect to R3.1, t he CISDT concurs that tagging evidence will suffice for this requirement.		

Organization	Yes or No	Question 2 Comment
Duke Energy	Yes	The tasks identified in Requirements 4 and 5 are performed by a third party vendor. Duke Energy is concerned with how an auditor will measure this requirement and that this would be an administrative burden on the BA. Duke Energy believes the actual reliability based need for R4 and R5 is contingent upon the failure of the third party vendor's tool and recommend revising the requirements to identify a process to ensure that the tasks preformed in R4 and R5 are completed by a sink BA when there is a failure.
Response: Thank you for your comment. The tasks defined in R4 and R5 are required at all times, regardless of whether or not a third party vendor tool is available. If a third party tool is being used, it is the responsibility of the Sink Balancing Authority to obtain information from that vendor necessary to demonstrate compliance with the requirements.		
SERC OC Review Group	Yes	The SDT is requested to consider modifying the Reliability Adjustment Arranged Interchange definition. The current definition language is: Reliability Adjustment Arranged Interchange - Request to modify Confirmed Interchange or Implemented Interchange for reliability purposes. Suggested modification follows: DELETE: "Request to modify a" ADD: Modified New definition: Modified Confirmed Interchange or Implemented Interchange for reliability purposes.
Response: Please see the CISDT's responses in the definition section.		
Dominion NERC Compliance Policy	Yes	Attachment 1; footnote numbers 5 & 7 are listed in the table, but there are no corresponding footnotes at the bottom of the pages.
Response: Thank you for your comment. These should have been 2 and 4 respectively and have been corrected.		
Florida Municipal Power Agency	Yes	Please see FMPA comments to Question 1. INT-006 is commercial in nature, duplicative of NAESB standards, and should be retired in accordance with P81 recommendations and the Independent Expert Review Panel recommendations.
Response: Please see the CISDT's response to Question 1.		

Organization	Yes or No	Question 2 Comment
ACES Standards Collaborators	Yes	(1) We appreciate the changes made to this standard and believe it is improved. However, we still have several issues with the standard. (2) The adjective “emergency” should be removed from requirement R1 because it causes confusion. The addition of this adjective to “Arranged Interchange” does nothing to change the requirement and may lead to confusion in registered entities trying to determine the purpose of delineating it. Each BA and TSP will still be required to approve or deny the Arrange Interchange regardless of whether it is an emergency Arranged Interchange or not. Thus, the adjective provides no clarification for what the requirement compels and will only lead to confusion. Please strike it from the requirement. (3) We disagree with the need for the BAs and TSPs to meet the timing requirements in column B of Attachment 1 per requirements R1 and R2 in an enforceable reliability standard. It is not necessary to meet timing requirements in column B for reliability and column B is, in fact, a business practice. Meeting timing requirements in Column D is all that is necessary for reliability. Consider if a BA or TSP fails to approve or deny an Arranged Interchange within two hours for a schedule submitted five hours before the ramp start. Reliability is not impacted if the schedule is ultimately approved in time for it to be implemented. The TSP or BA could take over four hours to approve and ultimately still transition the Arranged Interchange to Confirmed Interchange and then Implemented Interchange without any negative reliability impacts. Thus, column B timing is not ultimately what is needed for reliability. (4) INT-006-4 Part 1.2 - Denying Arranged Interchange or curtailing Confirmed Interchange because the scheduling path is invalid is a business practice issue. While we agree that this is a necessary task to comply with open access transmission tariffs, it is not a reliability issue but rather a business practice issue. Furthermore, this is a validation that should be performed automatically with tagging software. Thus, this part should be removed. (5) INT-006-4 Part 2.1 - Denying Arranged Interchange because the transmission path

Organization	Yes or No	Question 2 Comment
		is invalid is a business practice issue and is not a reliability issue. It provides no indication for whether the transmission system can handle the Arranged Interchange. This should be moved to a NAESB business practice. Furthermore, this is something that should be automatically handled via the tagging software and is obviated by the entrenched nature of the software. (6) INT-006-4 Part 3.1 is unnecessary and duplicative with the proposed NERC Board resolution for COM-002/COM-003 for developing the final standard. Part 3.1 does not reflect that an adjustment request may originate from other reliability entities such as BAs and may include arbitrary timelines. First, COM-002/COM-003 will compel three-part communication when preserving or changing the “state” of a Bulk Electric System Element. This could potentially compel communication of denial of Reliability Adjustment Arranged Interchange since curtailing a schedule could be viewed as changing the state. Second, Part 3.1 does not reflect that a reliability adjustment may be issued by a BA. It presumes that the adjustment comes from the RC by requiring communication to only the RC. Third, the basis for the need to communicate the denial within 10 minutes is not established or stated in the technical guidelines section. Without such basis, we can only assume it is arbitrary. We recommend striking Part 3.1 from the standard. (7) The clause “the time period specified in Attachment 1, Column B, has elapsed” should be struck from the third bullet of requirement R4. It is unnecessary as the only conditions necessary are that the Arranged Interchange has not been denied and it is not a Reliability Adjustment Arranged Interchange. (8) INT-006-4 Part 5.5 - PSE has been replaced in many parts of the proposed modifications to the INT standards with LSE. Part 6.4 compels notification of approvals and denials to the PSE but there is no companion part to compel notification to the LSE. Is this intended? (9) INT-006-4 - Guideline and Technical Basis - The first main bullet on page 16 and its sub-bullets need to be modified. The main bullet states that the LSE “that approves or denies Arranged Interchange”. The LSE does neither. The LSE submits a

Organization	Yes or No	Question 2 Comment
		Request for Interchange that becomes Arranged Interchange once the appropriate reliability entities receive and approve the request. The second associated sub-bullet in combination with the main bullet states that the LSE is responsible for communicating of the Arranged Interchange to the Sink Balancing Authority. Again, the LSE does not approve or deny so it cannot communicate approval or denial. (10) INT-006-4 - Guideline and Technical Basis - The first sub-bullet under the second main bullet on page 16 refers to communication that occurs between BAs, TSPs and PSEs. This is not consistent with the remainder of the proposal which focuses on replacing PSEs with LSEs.
Response: Thank you for your comments. **1) Thank you.** **2) An emergency RFI may not be "on-time" and this is why it is delineated in the requirement.** **3) It would not be reliable for entities to consistently deny just before ramping begins. These provide a reasonable amount of time for each entity to perform their evaluation, allow for correction of any issues that are identified and allow time for to prepare the system.** **4) This requirement part is included to ensure that all entities on the path are notified of the transaction so that they may perform a reliability assessment.** **5) This requirement part is included to ensure that all entities on the path are notified of the transaction so that they may perform a reliability assessment.** **6) The CISDT believes that the tagging system will suffice for this requirement.** **7) Since an entity can approve even after denying, the Arranged Interchange is not set to a denied state until the time period has expired** **8) It is intended that all PSEs on the Interchange are notified; therefore the LSE would be included in the PSE notifications.** **9) The CISDT did not modify this language since the NAESB functional specification allows for an LSE to have approval rights** **10) The CISDT did not change this language since this description is referring to the more general PSE as identified in the NAESB functional specification.**		
Bonneville Power	Yes	o Requirement 2BPA recommends the sub-requirements worded and numbered similar to R1.1 and R1.2 under R1 be added under R2: Change current draft R2.1 to

Organization	Yes or No	Question 2 Comment
Administration		R2.2 in regard to path and proper connectivity with adjacent TSP's and insert a new R2.1 worded similar to R1.1 to address interchange magnitude. For example:2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.2.2. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid. o Requirement 5 BPA requests clarification on how R5 will be implemented. Does the drafting team expect JESS/NAESB to make changes in the NAESB Tagging specification prior to the changes in the NERC Interchange standards? BPA recommends a 60-90 day bandwidth to allow entities to make necessary changes to meet this requirement. o VSL Section, R5BPA requests clarification on the paragraph in High VSL column as it matches to the first paragraph in Severe VSL column. Should the word "OR" between the two risks description in the Severe VSL column be an "AND"? If no, how do NERC and WECC assess which severity level to apply when a Sink BA does not notify all of the entities listed in R5.1-5.5? o Attachment 1 - Timing Tables For clarification, BPA recommends modifying footnote 5 to read: "See NAESB WEQ004 Timing Tables, this table is a partial repeat of the NAESB Timing Table containing only items which are applicable to this standard."
Response: Thank you for your comment. With respect to R2, the CISDT does not agree with this suggestion. The CISDT does not believe that the TSP is responsible for evaluating being able to support the magnitude of the interchange or ramping capability. With respect to R5, the CISDT does not expect any changes will be required to the NAESB Tagging specification. With respect to the VSL section, the VSLs have been better distinguished. With respect to Attachment 1, the CISDT believes this is comparable to the language that is currently in the standard. Stakeholder consensus has been reached on this item and the CISDT will not be		

Organization	Yes or No	Question 2 Comment
modifying the language.		
Colorado Spings Utilities	Yes	Thank you standard drafting team for all of your efforts. Please revise the VSL levels for this standard. The Violation Severity Levels are inappropriately high and disproportional to the risk to the Bulk Electric System.
Response: Thank you for your comment. The CISDT reminds these commenters that VRFs measure the impact to reliability of violating a specific requirement and VSLs measure the degree to which a standard was violated. A standard can have a Lower VRF, because violating it would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, and still have Severe VSL, indicating that the requirement is pass/fail. As the VSL Guidelines state, "If the required performance cannot be broken down to categorize degrees of noncompliant performance that at least partially meet the reliability objective of the requirement, any noncompliance with the requirement will have only one VSL – Severe."		
NextEra Energy/Florida Power and Light	Yes	This standard is primarily a proposed business practice and should be mostly transferred to NAESB and replaced with a single requirement that captures the single reliability essence contained in the standard. Proposed language for the requirement is as follows: R1. Each Balancing Authority and Transmission Service Provider that receives an Arranged Interchange shall evaluate it with respect to their respective obligation pursuant to the Arranged Interchange to ensure it is accurate, complete and that they have the resources, facilities and capability to implement the Arranged Interchange as Confirmed Interchange prior to approving the Arranged Interchange to be transitioned to Confirmed Interchange. Any requirements above or beyond this R1 should be driven by market needs, not a NERC reliability standard. Additionally, the timing requirements in Attachment 1 are arbitrary, not reliability based and are better determined based on market needs through NAESB then by NERC through a reliability standard. As long as Arranged Interchange is evaluated from a reliability prospective the BA's and TSP's prior to being transitioned to Confirmed Interchange, any reliability issues related to the interchange transactions should be identified and addressed by the Balancing Authorities and Transmission Service Providers.
Response: The CISDT appreciates your comments and suggested language but stakeholder consensus has been reached and these		

Organization	Yes or No	Question 2 Comment
requirements will not be modified.		
Manitoba Hydro	Yes	(a) Purpose - wondering whether the reference to ‘entities’ should more appropriately be ‘responsible entities’ (b) R1 - the use of the word ‘expect’ is very open. Without further qualifying language, parties will proceed on the assumption that this is completely within the Balancing Authority’s own judgment. (c) M1 - there is no measure that addresses the requirement 1.1 and 1.2 (d) M2 - the language of this measure does not match the language of the requirement. In order to be consistent with the language of the requirement, the measure should read “....that it responded to each Arranged Interchange or emergency Arranged Interchange within the time defined in Attachment 1...” (e) M3 - the language of the measure does not match the language of the requirement with respect to the communication of the denial. It should appropriately read “...or denied the request and, if applicable, communicated denial to the Reliability Coordinator....” (f) M5 - ‘is’ should be ‘was’
Response: The CISDT appreciates your comments. **a) This clarification has been made to the Purpose Statement.** **b) Part 1.1 requires the BA to deny a tag if it does not believe that it can meet the ramp or other considerations of a particular schedule. The BA must rely on its expertise in its own operations to make this decision.** **c) While M1 does not explicitly call out Parts 1.1 and 1.2, it does include the notation of “(R1)” at the end, which includes all of the Requirement and its Parts.** **d) This correction has been made to M2.** **e) This correction has been made to M3** **f) This correction was made to M5.**		

Organization	Yes or No	Question 2 Comment
ReliabilityFirst Corporation	Yes	ReliabilityFirst votes in the negative because the use of bullets (or statements) in Requirement R4 is not consistent with the wording of the parent requirement. This has the possibility of creating compliance issues and lead to potential interpretations. ReliabilityFirst offers the following comments for consideration: 1. Requirement R1 and R2a. ReliabilityFirst requests further clarification on meaning of the term "on-time" which proceeds the term "Arranged Interchange". Does the "on-time" have a specific meaning within the standard and if so, ReliabilityFirst recommends making it a defined term. 2. Requirement R4a. Requirement R4 States "...that none of the following conditions" and there are three bullets associated with the requirement. Bullets are considered "or" statements in Reliability Standards and ReliabilityFirst believes that these are should be "and" statements. Thus, ReliabilityFirst recommends reformatting the bullets to become sub-parts (i.e., 4.1, 4.2 and 4.3). Without this modification, there is a high probability for potential compliance complications and possible interpretations. 3. VSL Requirement R5a. The High VSL and the first Severe VSL seem to be saying the same thing. ReliabilityFirst recommends the following for consideration for the High VSL: "The Sink Balancing Authority notified all but one of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange."
Response: Thank you for your comment. **1. The CISDT does not believe a defined term is required since the term on-time is described in the Time Classification column of the INT-006 Attachment 1.** **2. The CISDT believes bullets are appropriate. If any of these bullets apply the Arranged Interchange will not be transitioned to Confirmed Interchange therefore it is an 'or' condition.** **3. The CISDT has modified the VSLs**		
Seminole Electric Cooperative, Inc.	Yes	Requirement R4 as written is ambiguous and confusing and we suggest it be re-worded. Specifically, the language requiring the Sink BA to confirm the double

Organization	Yes or No	Question 2 Comment
		negatives stated in the requirement, should be re-written to simplify.
Response: Thank you for your comment. The CISDT has considered many different versions of this language in attempt to simplify and could not find another way to state this in results bases standard language.		
Powerex Corp.	Yes	Powerex has reviewed the latest draft of the Interchange Standards and considers these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are important and prevent entities that transact from providing false and misleading information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is implemented in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations. Powerex does not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards. There does not appear to be any requirement that prescribes, at a minimum, that an Interchange Transaction or Interchange Schedule must be submitted for energy that flows between Balancing Authorities. This should be the case, and a new requirement should be developed to reflect this. Otherwise some entities may choose not to submit certain interchange transactions even though it may affect adjacent Balancing Authorities and TSPs. This standard must prescribe at a minimum the verification and validations that must be performed during the reliability assessment by a BA and TSP. Those minimum requirements should not be prescribed in the Technical Guidance section of the standard because they would not be considered mandatory and could be ignored by Responsible Entities. It is imperative that this standard provide clear requirements that ensure BA and TSP are validating impacts, and not allowing transactions to flow that will cause issues within the interconnection. For example, a Source BA should validate and not allow a generator to schedule above and beyond its nameplate capacity to ensure accurate scheduling. Powerex believes that a

Organization	Yes or No	Question 2 Comment
		Source BA will only perform these types of checks if there is a prescribed minimum requirement within a standard, and suggests that the CISDT provide the minimum set of validations. R1 and R2 does not hold the BA or TSP accountable to correctly approve or deny the interchange request the first time, and allows the entities to rectify the issue through curtailment of the interchange. Powerex believes that these requirements should be modified to rectify a possible loophole that could lead to inefficient scheduling practices.M1 and M2 should measure the times the BA or TSP approves a request without proper verification or validation and then subsequently curtails the interchange once they realize the mistake. The BA or TSP should perform a thorough validation of an Arranged Interchange to avoid such instances which rectify BA or TSP mistakes. Powerex suggests that when a BA or TSP reevaluates a Confirmed Interchange that they note in the comments the reason for the reevaluation. For Attachment 1, there should be a reference point for the time that constitutes whether or not an Arranged Interchange is "on-time" or not. The previous Standard (INT-006-3) used to have the second column of the Timing Requirements table labeled as "IA Assigned Time Classification". The new table heading for the second column is not assigned to an entity and states just "Time Classification" and should state "Sink BA Time Classification". This will result in potential disputes as to who determines and classifies whether or not the RFI is "on-time". An Entity should be assigned the responsibility to determine the correct time classification (On-Time, Late, etc). Powerex suggests that the Sink BA be the Responsible Entity, and that once the Sink BA assigns a classification that other approval entities should respect that classification.

Response: Thank you for your comment. The CISDT does not believe the wording in these requirements presents a loophole; it provides the ability to modify the status of the Interchange if an issue is identified after the initial approval.

With respect to Attachment 1, the CISDT does not believe that a second time classification column is required. We do not understand how different entities would determine different time classifications; if transactions are submitted so close to the border of a time classification such that processing could impact the results that is a risk to be borne by the submitter.

Organization	Yes or No	Question 2 Comment
PJM Interconnection	Yes	PJM supports the language in R1; however, the measures in M1 do not appear to cover R1.1 and R1.2. PJM suggests that the drafting team modify M1 to address these requirements. PJM supports the language in R2, R4 and R5. PJM supports the language in R3; however, there appears to be a potential typo in M3: " . . . or denied the request or that it communicated denial to the Reliability Coordinator" should read " . . . or denied the request and that it communicated denial to the Reliability Coordinator." PJM supports the revision to the Attachment 1 Timing Tables, but offers that in the draft that was reviewed, there appears to be a potential typo in the superscripts for columns A and C in both tables, as they superscripts do not match existing footnotes.
Response: Thank you for these comments. The CISDT has considered the comments and applied those found relevant as indicated in the redline.		
City of Austin dba Austin Energy	Yes	City of Austin dba Austin Energy (AE) respectfully requests consideration of the following comment: Requirement R4 contains a number of double negatives making it unnecessarily confusing. Please consider the following language: “Prior to transitioning an Arranged Interchange to Confirmed Interchange, each Sink Balancing Authority shall confirm the following conditions exist: (i) the time period specified in Attachment 1, Column B has elapsed and (ii) if it is a Reliability Adjustment Arranged Interchange, the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has communicated its approval of the transition, or if it is not a Reliability Adjustment Arranged Interchange, (a) all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition and (b) no entity associated with the Arranged Interchange has communicated its denial of the transition.” We suggest the SDT format the foregoing language to aid in comprehension. We also ask that the SDT consider whether both (a) and (b) are truly necessary. If approval/denial is a binary choice, then satisfying (a), that is, having all BAs’ and TSPs’ approval, should be sufficient.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. The CISDT recognizes this wording can be confusing but has considered many alternatives. With your suggested language, no Arranged Interchange would transition to Confirmed Interchange until after the time period specified in Attachment 1, Column B had expired. If all parties have approved the Arranged Interchange we do not want to wait until the time period has expired before confirming to Confirmed Interchange.		
MISO	Yes	

3. **INT-009-2: Do you have any comments relating to INT-009-2? Please provide specific suggestions for improvement, including alternate language.**

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT reviewed and considered all comments, and it believes that only minor, non-substantive changes to the standard are necessary. The standard will proceed to final ballot.

The purpose statement has been edited to better reflect the content and intent of the standard; clarifying changes were made to R1 and M1 for consistency and to better reflect the standard's intent; a clarifying notation for "Net Interchange Actual" was added to R2; and "if applicable" was removed from R3.

Many commenters expressed concern about redundancy with R2 and BAL-005-2b. The CISDT is aware that a requirement exists in the BAL-005-2b standard describing how Dynamic Schedules are used in the ACE equation; however, there is no comparable requirement for Pseudo-Ties. INT-009-2 R2 fills that gap. INT-009-2 R2 can be retired in the future if BAL-005-2b is updated to reflect the reference to Pseudo-Ties.

Minority comments are addressed below, in responses to individual commenters.

Organization	Yes or No	Question 3 Comment
Nebraska Public Power District	No	I am concerned that the BA in which a DC line that crosses interconnection boundaries exists is not treated as a source/sink BA. The BA in which a DC line that crosses an interconnection boundary terminates, needs to have the ability to approve or deny these tags, based upon more than just the path between BA's being correct. In addition, I am concerned that valid reasons for denying a reliability related interchange curtailment are not specified. We run into times when the DC tie trips and curtailments get denied by the sink (PJM). As a result the energy must be made up by the BA on the same side of the DC tie as the sink BA. The sink BA simply denies the curtailment even though the source has effectively tripped off-line. The BA that was not involved in the transaction is now on the hook to provide the MW immediately. This is not conducive to reliability and needs to be corrected.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. This situation falls outside of the scope of R3 of INT-009-2. Approval rights for curtailments by intermediate BAs are not addressed in this standard.		
Northeast Power Coordinating Council	No	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
Duke Energy	No	
MRO NERC Standards Review Forum	No	
Colorado Spings Utilities	No	
American Electric Power	No	
Central Lincoln	No	
NIPSCO	No	
s	No	
Independent Electricity	No	

Organization	Yes or No	Question 3 Comment
System Operator		
Seminole Electric Cooperative, Inc.	No	
Seattle City Light	Yes	Seattle City Light supports the position of Next Era. Specifically:R1, R2 and R3 should be replaced with a single requirement that better captures the stated purpose of this standard ("To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process and maintain the generation-to-load balance.")The proposed single requirement is: R1. Each Balancing Authority that receives a non-dynamic Confirmed Interchange shall implement such Confirmed Interchange prior to the later of i) the start of the ramp; and ii) one minute after a non-dynamic Arranged Interchange is transitioned to Confirmed Interchange. Issues with the individual requirements are as follows: R1 seems to partially reflect some party's business practice and is more suitable for adaption by NAESB than NERC. While, with some work, it could help identify instants when a BA failed to properly implement a schedule transaction, it does not require a BA to actually "implement Interchange as agreed upon in the Interchange confirmation process", which is the stated purpose of this standard. It also allows BA's to agree to hourly or multiple-hour Composite Confirmed Interchange, and allows agreements to be reached before, after or during the time the Composite Confirmed Interchange occurs or even once a month. R2 does not add anything obligation on a BA to "ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process" and does not belong in this standard. Clearly, its inclusion in this standard is an attempt to remedy a perceived deficiency in BAL-005-.2b. The appropriate place to fix such deficiency, if indeed BAL-005-.2b is deficient, is within BAL-005.2b, not INT-009-2.

Organization	Yes or No	Question 3 Comment
		R3 is unnecessary, just like it is unnecessary to include a requirement that requires each BA in whose area the generation is controlled shall coordinate the Confirmed Interchange with the Generation Operator of the generation if applicable. Any BA that contains a DC tie already has processes and procedures for coordinating its use just like all BA's have with individual generators within their BA. If the industry believes the better processes or procedures are required, NAESB is a more appropriate organization to develop them than NERC. Finally, if the phrase "and maintain the generation-to-load balance" contained in the Purpose statement seems to be out of place and extraneous to implementing the Interchange as agreed upon. By removing it, the purpose is better focused.
Response: Thank you for your comments. The CISDT appreciates the suggestion for consolidating the requirements, but has decided to retain the individual requirements, as most stakeholders support them. **With respect to R1, the CISDT believes that existing language more appropriately addresses the CISDT intent than your proposed language.** **The CISDT has also retained R2. The CISDT observed that a requirement exists in the BAL-005-2b standard describing how Dynamic Schedules are used in the ACE equation; however, there is no comparable requirement for Pseudo-Ties. This requirement is here to fill this gap. This can be retired in the future if the BAL-005-2b standard is updated to reflect this requirement.** **With respect to R3, the CISDT maintains that there are TOPs that are not aware of Interchange by any other means and has therefore retained this requirement. The BA has a responsibility to coordinate with them to ensure that the flow on the DC tie reflects the Interchange.** **The CISDT agrees with your suggestion about the purpose statement and has revised it to better reflect the content of the standard.**		
ISO/RTO Standards Review Committee	Yes	Comments: Requirement #3Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie if applicable. Suggest to remove "if applicable". If the condition exists, what else

Organization	Yes or No	Question 3 Comment
		would make the condition non-applicable to the standard?
Response: Thank you for your comment. The SDT agrees and has removed "applicable."		
PacifiCorp	Yes	Requirement R1: As indicated in our previous comments, it is unclear to PacifiCorp what the distinction is between Net Scheduled Interchange and Composite Confirmed Interchange in Requirement R1. Although Net Scheduled Interchange has been defined as the "algebraic sum of all interchange schedules across a given path" and Composite Confirmed Interchange is based on the "aggregate of all confirmed interchange," PacifiCorp does not see the two terms as being distinct from one another in practice. To avoid confusion, PacifiCorp recommends keeping Net Scheduled Interchange as the only term referenced in the requirement. Requirement R2: PacifiCorp maintains that the addition of this requirement is redundant. The Rationale for R2 only reinforces this point. If R2 is "equivalent to R10 of BAL-005-2b," why is the inclusion of R2 in INT-009-2 necessary? Wouldn't the existence of an "equivalent" requirement in another standard be grounds for its removal under Paragraph 81?
Response: Thank you for your comment. With respect to R1, the CISDT believes the new term "Composite Confirmed Interchange" provides flexibility in dealing with profiles over time while the existing term "Net Scheduled Interchange" represents a single value at one point in time. **The CISDT has retained R2. The CISDT observed that a requirement exists in the BAL-005-2b standard describing how Dynamic Schedules are used in the ACE equation; however, there is no comparable requirement for Pseudo-Ties. This requirement is here to fill this gap. This can be retired in the future if the BAL-005-2b standard is updated to reflect this requirement.**		
SPP Standards Review Group	Yes	In consideration of the Paragraph 81 effort, we suggest retiring R10 in BAL-005-0.2b. There is no need to have this requirement in both BAL-005-0.2b and INT-009-2. We suggest the following wording for R3: Each Balancing Authority in whose area a high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of that high-

Organization	Yes or No	Question 3 Comment
		voltage direct current tie if applicable. Additionally, we do not understand what the 'if applicable' at the end of the requirement is referring to. Is it the BA or is it something else? If it is indeed the BA, we suggest deleting the phrase since it doesn't add any clarification to the requirement. If it isn't referring to the BA, then please add additional clarification such that the reference can be understood.
Response: Thank you for your comment. The CISDT has retained R2 in INT-009-2 The CISDT has retained R2, though it has observed that a requirement exists in the BAL-005-2b standard describing how Dynamic Schedules are used in the ACE equation. However, there is no comparable requirement for Pseudo-Ties. This requirement is here to fill this gap. This can be retired in the future if the BAL-005-2b standard is updated to reflect this requirement. The CISDT agrees with your wording suggestion for R3, and has removed the "if applicable" from the requirement.		
SERC OC Review Group	Yes	The SDT is respectfully requested to clarify that a Pseudo-Tie is not a physical tie that actually exists.
Response: Thank you. Please see the response to this comment is other sections		
Dominion NERC Compliance Policy	Yes	Throughout the entire Standard, Pseudo-Tie needs to be corrected to read as Pseudo-tie, as changed in the definition.
Response: Thank you for your comment. Pseudo-Tie has been made consistent throughout the documents.		
Florida Municipal Power Agency	Yes	FMPA would have supported this standard but for the definitions. Please see our comments on definitions.
Response: Thank you for your comment. See responses to your comments on the definitions.		
ACES Standards Collaborators	Yes	(1) INT-009-2 R1 - This requirement is redundant with BAL-006-2 R4, which already requires Adjacent BAs to operate to a "common Net Interchange Schedule and Actual Net Interchange value" with opposite signs. Redundancy is one of the paragraph 81

Organization	Yes or No	Question 3 Comment
		criteria. Please remove the redundancy to avoid implementing requirements that will be retired later. (2) INT-009-2 R2 - This requirement also meets Paragraph 81 criteria because it is redundant with BAL-005-0.2b R12 and R12.3. The BAL-005 standard already requires the BAs to use a common metering point for Pseudo-Ties and Dynamic Schedules.
Response: Thank you for your comments. (1) BAL does not have an exclusion for Dynamic Schedules and does not have an inclusion for INT-010 R1-R3. (2) The CISDT has retained R2. The CISDT observed that a requirement exists in the BAL-005-2b standard describing how Dynamic Schedules are used in the ACE equation; however, there is no comparable requirement for Pseudo-Ties. This requirement is here to fill this gap. This can be retired in the future if the BAL-005-2b standard is updated to reflect this requirement.		
Bonneville Power Administration	Yes	o Definitions o Dynamic Schedule BPA recommends the drafting team remove the word “time-” from “A time-varying energy transfer that is update . . .” The term time-varying is inaccurate; the amount of energy varies while time does not. o Pseudo-TieBPA recommends the drafting team remove the word “time-” from “A time-varying energy transfer that is update . . .” The term time-varying is inaccurate; the amount of energy varies while time does not. o R1 contains the term “Pseudo-tie”, whereas in Measure 1 and in VSL Section for R1 do not contain the term “Pseudo-tie”. BPA requests clarification on why the term “Pseudo-tie” in R1 but not in M1 and in the VSL for R1?
Response: Thank you for your comment. The CISDT has added “Pseudo-Tie” to M1 and the VSL.		
NextEra Energy/Florida Power and Light	Yes	R1, R2 and R3 should be replaced with a single requirement that better captures the stated purpose of this standard (“To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process and maintain the generation-to-load balance.”)The proposed single requirement is:

Organization	Yes or No	Question 3 Comment
		R1. Each Balancing Authority that receives a non-dynamic Confirmed Interchange shall implement such Confirmed Interchange prior to the later of i) the start of the ramp; and ii) one minute after a non-dynamic Arranged Interchange is transitioned to Confirmed Interchange. Issues with the individual requirements are as follows: R1 seems to partially reflect some party's business practice and is more suitable for adaption by NAESB than NERC. While, with some work, it could help identify instants when a BA failed to properly implement a schedule transaction, it does not require a BA to actually "implement Interchange as agreed upon in the Interchange confirmation process", which is the stated purpose of this standard. It also allows BA's to agree to hourly or multiple-hour Composite Confirmed Interchange, and allows agreements to be reached before, after or during the time the Composite Confirmed Interchange occurs or even once a month. R2 does not add anything obligation on a BA to "ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process" and does not belong in this standard. Clearly, its inclusion in this standard is an attempt to remedy a perceived deficiency in BAL-005-.2b. The appropriate place to fix such deficiency, if indeed BAL-005-.2b is deficient, is within BAL-005.2b, not INT-009-2. R3 is unnecessary, just like it is unnecessary to include a requirement that requires each BA in whose area the generation is controlled shall coordinate the Confirmed Interchange with the Generation Operator of the generation if applicable. Any BA that contains a DC tie already has processes and procedures for coordinating its use just like all BA's have with individual generators within their BA. If the industry believes the better processes or procedures are required, NAESB is a more appropriate organization to develop them than NERC. Finally, if the phrase "and maintain the generation-to-load balance" contained in the Purpose statement seems to be out of place and extraneous to implementing the Interchange as agreed upon.

Organization	Yes or No	Question 3 Comment
		By removing it, the purpose is better focused.
Response: Thank you for your comments. The CISDT appreciates the suggestion for consolidating the requirements, but has decided to retain the individual requirements, as most stakeholders support them. **With respect to R1, the CISDT believes that existing language more appropriately addresses the CISDT intent than your proposed language.** **The CISDT has also retained R2. The CISDT observed that a requirement exists in the BAL-005-2b standard describing how Dynamic Schedules are used in the ACE equation; however, there is no comparable requirement for Pseudo-Ties. This requirement is here to fill this gap. This can be retired in the future if the BAL-005-2b standard is updated to reflect this requirement.** **With respect to R3, the CISDT maintains that there are TOPs that are not aware of Interchange by any other means and has therefore retained this requirement. The BA has a responsibility to coordinate with them to ensure that the flow on the DC tie reflects the Interchange.** **The CISDT agrees with your suggestion about the purpose statement and has revised it to better reflect the content of the standard.**		
Manitoba Hydro	Yes	(a) R1 - the word 'Adjacent' should be added before the words 'Balancing Authority' in the second line. (b) M1 - the language of the measure is missing a few concepts that are in the requirement. i.e. 'and Pseudo-ties' should be added after Dynamic Schedules', and 'by a Reliability Coordinator' should be added after 'as directed'. (c) R2, M2 (and VSLs) - the standard uses the term Net Interchange Actual but the Glossary defined term which I assume is desired to be used is Net Actual Interchange.
Response: Thank you for your comments. (a) The CISDT agrees. (b) The CISDT has added Pseudo-Ties but removed "by a Reliability Coordinator" from R1. (c) The term that the CISDT intended to use it the Net Interchange Actual (NI_A) term in the ACE equation. This notation has been added to R2.		

Organization	Yes or No	Question 3 Comment
ReliabilityFirst Corporation	Yes	ReliabilityFirst abstains and offers the following comment for consideration:1. Requirement R1a. ReliabilityFirst believes Reliability Standards should stand on their own merit and should not reference other Reliability Standards. The reference to INT-010-2 may cause issues if the intent of the INT-010-2 standard changes in the future. Furthermore, with the reference to the INT-010-2 standard the approval of INT-009-2 is completely dependent to the approval of the INT-010-2 (i.e., the approval of the INT-009-2 is dependent on the INT-010-2 standard).
Response: Thank you for your comment. The SDT believes the cross reference is required, the flows created by INT-010 must be incorporated into the INT-009 process.		
MidAmerican Energy	Yes	Requirement R2: This requirement is redundant. As identified in the rationale box, the requirement is equivalent to BAL-005-2b. To avoid double jeopardy, the R2 requirement in INT-009-2 should be removed and any remaining concerns should be addressed in BAL-005.
Response: Thank you for your comment. The CISDT has retained R2. The CISDT observed that a requirement exists in the BAL-005-2b standard describing how Dynamic Schedules are used in the ACE equation; however, there is no comparable requirement for Pseudo-Ties. This requirement is here to fill this gap. This can be retired in the future if the BAL-005-2b standard is updated to reflect this requirement.		
Exleon Companies	Yes	INT-009-2 includes new definitions for Dynamic Schedule and Pseudo-Tie requiring that these values be treated as Interchange Schedules and Actual Interchange, respectively, and included in ACE equations. It is confusing, then, that R1 should specify that Composite Confirmed Interchange is to be calculated without inclusion of Dynamic Schedules and Pseudo-Ties. As Dynamic Transfers represent inputs to the ACE equation, and measurements against which a BA is managing its balancing function, to exclude them from the Composite Confirmed Interchange seems to paint an inaccurate picture of the Interchange between two Balancing Authorities. If the intention is to not skew Composite Arranged Interchange by the inclusion of values that change in Real Time with no settled value available until after-the-fact, that can

Organization	Yes or No	Question 3 Comment
		be accomplished by stipulating that estimated values of Dynamic Schedules and Pseudo-Ties not be included in Composite Confirmed Interchange, and that the real-time values should be used for calculation of Composite Confirmed Interchange in the Real Time horizon, with the agreed on after the fact values used for calculation of Composite Confirmed Interchange in the after the fact horizon.
Response: Thank you for your comment. The CISDT has chosen to retain the current language of the requirement and definition so not to preclude the use of the defined terms in other standards.		
Kansas City Power & Light	Yes	BAL-005-0.2b R10 is the same requirement as in INT-009-2 so we have a duplicate requirement in both standards. In order to remove duplication, BAL-005-0.2b R10 could be retired in reference to Paragraph 81. R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie if applicable. One would think BA and TOP coordination over the HVDC would be applicable all the time, would it not? In what conditions would it not be coordinated?
Response: Thank you for your comment. The CISDT has retained R2. The CISDT observed that a requirement exists in the BAL-005-2b standard describing how Dynamic Schedules are used in the ACE equation; however, there is no comparable requirement for Pseudo-Ties. This requirement is here to fill this gap. This can be retired in the future if the BAL-005-2b standard is updated to reflect this requirement. With respect to R3, the CISDT has removed "if applicable" from the requirement.		
Powerex Corp.	Yes	Powerex has reviewed the latest draft of the Interchange Standards and considers these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are important and prevent entities that transact from providing false and misleading information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is implemented

Organization	Yes or No	Question 3 Comment
		in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations. Powerex does not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards.
Response: Thank you for your support!		
PJM Interconnection	Yes	PJM supports the language in R1. PJM supports the language in R2, but asks the drafting team to consider providing accommodation for existing Pseudo-Ties. The effective date listed in the implementation plan does not provide sufficient time for the coordination required to modify existing Pseudo Ties. PJM does not support the language in R3, as written. Specifically, 1. The qualifier "if applicable" is ambiguous and suggests that there exist situations in which a Balancing Authority would not be required to coordinate with a Transmission Operator. If this is the case, the requirement should clearly outline these situations. 2. This requirement carries an unduly heavy compliance burden as there exist no options to streamline the coordination effort via agreements or technical solutions that mitigate the need for active coordination. BAs and TOPs should have an option to reduce their compliance burden in situations such as the TOP allowing the BA to directly control the HVDC tie via a telemetered control signal or when the TOP chooses to actively monitor E-Tag software and/or the BA's scheduling system to facilitate the operation of their HVDC facility.
Response: Thank you for your comment. The CISDT has removed "if applicable" from R3. The CISDT believes that the actions that you mention in your second comment are examples of the type of coordination envisioned by the team with respect to this requirement.		
Tacoma Power	Yes	R1, R2, and R3 should be replaced with a single requirement that captures the stated purpose, "To ensure that BAs implement the Interchange as agreed upon in the Interchange confirmation process and maintain the generation-to-load

Organization	Yes or No	Question 3 Comment
		balance."Proposed single requirement:"R1. Each Balancing Authority that receives a non-dynamic Confirmed Interchange shall implement such Confirmed Interchange prior to the later of i) the start of the ramp; or ii) one minute after the non-dynamic Arranged Interchange is transitioned to Confirmed Interchange."
Response: Thank you for the proposed language. The CISDT has decided to retain the three requirements of this standard.		
City of Austin dba Austin Energy	Yes	City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Thank you for your comment. Please see the CISDT's response to Seattle City Light's comments.		
MISO	Yes	

4. INT-010-2: Do you have any comments relating to INT-010-2? Please provide specific suggestions for improvement, including alternate language.

Summary Consideration:

The CISDT thanks all commenters for their feedback on INT-010-2. In response to industry comments, the CISDT has added language and a rationale box to R1, deleted R4, and made minor changes to other requirements.

With respect to R1, the CISDT has added language and a Rationale box to provide clarity around "energy sharing agreement." The requirement was modified to read "covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement" (rather than just "covered by an energy sharing agreement") and a rationale was added:

Rationale for R1: This requirement was originally revised to replace the term "request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

Comments received indicate industry consensus for removing Requirement R4. Industry has commented that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit. The CISDT agrees and has removed R4.

In response to industry comments, and for consistency or to correct typos, minor changes were also made to the Applicability Section, R1, R2, M2, and M3.

Minority comments are addressed below, in responses to individual commenters.

Organization	Yes or No	Question 4 Comment
MISO	No	R2.3 of INT-004 states that the LSE is responsible for maintaining the RFI for Reliability Adjustment requests. If the Pseudo-Ties are implemented through an

Organization	Yes or No	Question 4 Comment
		agreed upon alternate congestion management approach (such as reporting market flows or generation-to-load flows to the IDC), the IDC will assign a relief obligation to the BA. The BA will redispatch its system to meet the relief obligation which may or may not involve a change to the pseudo-tie output. In this instance, it is not appropriate to limit the pseudo-tie output in the ACE equation to a reliability cap if other generation is being redispatched to meet the relief obligation. Therefore it is recommended this requirement be removed.
Response: Thank you for your comment. Comments received indicate industry consensus for removing Requirement R4. Industry has commented that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit. The CISDT agrees and has removed R4.		
Nebraska Public Power District	No	Requirement 2.3 of INT-004 states that the LSE is responsible for maintaining the RFI for Reliability Adjustment requests. If the Pseudo-Ties are implemented through an agreed upon alternate congestion management approach (such as reporting market flows or generation-to-load flows to the IDC), the IDC will assign a relief obligation to the BA. The BA will redispatch its system to meet the relief obligation which may or may not involve a change to the pseudo-tie output. In this instance, it is not appropriate to limit the pseudo-tie output in the ACE equation to a reliability cap if other generation is being redispatched to meet the relief obligation. Therefore it is recommended this requirement be removed.
Response: Thank you for your comment. Comments received indicate industry consensus for removing Requirement R4. Industry has commented that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit. The CISDT agrees and has removed R4.		
City of Austin dba Austin Energy	No	City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Thank you. Please refer to the SDT's response to Seattle City Light.		

Organization	Yes or No	Question 4 Comment
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
PacifiCorp	No	
Duke Energy	No	
Colorado Spings Utilities	No	
American Electric Power	No	
Central Lincoln	No	
MidAmerican Energy	No	
Exleon Companies	No	
Northeast Power Coordinating Council	Yes	The notation “4.2” in Section A4 Applicability should be removed. Suggest revising Requirement R2 as follows: R2. Each Sink Balancing Authority shall submit a Reliability Adjustment Arranged Interchange reflecting that modification within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. With the wording change, corresponding changes must be made to the Measures and the VSLs as appropriate. The above

Organization	Yes or No	Question 4 Comment
		wording change to R2 is also proposed for the other requirements in this standard where applicable.
Response: Thank you for your comment. The SDT has removed the notation in Section A4. With respect to your comment on R2, the Sink BA is responsible for ensuring that the tag is updated or created, but the Sink BA may not be the entity that actually submits the revised tag. R2 has not been modified.		
Independent Electricity System Operator	Yes	1. The notation "4.2" in Section A4 Applicability should be removed. 2. While we understand and support the intent of Requirement R2, we suggest it be revised as indicated below to remove the term "shall ensure" which may not be measurable.R2. Each Sink Balancing Authority shall submit a Reliability Adjustment Arranged Interchange reflecting that modification within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. If the SDT accepts the proposed wording change, then please make corresponding changes to the Measures and the VSLs as appropriate. The above wording change to R2 is also proposed for other requirements in this standard, where appropriate.
Response: Thank you for your comment. The SDT has removed the notation in Section A4. With respect to your comment on R2, the Sink BA is responsible for ensuring that the tag is updated or created, but the Sink BA may not be the entity that actually submits the revised tag. R2 has not been modified.		
Seattle City Light	Yes	Seattle City Light supports the concerns of NextEra regarding this draft. Specifically, "This standard appears to be more directed a correcting a perceived inequity in congestion management procedures and/or in energy sharing agreements for reliability than in promoting or ensuring real-time reliability. R1, R2 and R3 should be retired (using the paragraph 81 criteria), and possibly transferred to NAESB. They do nothing to impact real-time reliability, and could actually adversely impacts reliability if a RFI for reliability fails to get implemented within the arbitrary 60 minute windows specified in these requirements and the energy scheduled for reliability reasons

Organization	Yes or No	Question 4 Comment
		prematurely ends. Additionally, any limitations on how long energy sharing transactions or RC directed schedules for reliability reason should be exempted from standard interchange scheduling processes and procedures should be addressed by NAESB, not NERC. Finally, R4 does not belong in an INT standard. It is unclear how capping the MW value in ACE equations helps ensure reliability. While a cap may change which BA supplies the energy above the MW cap, it does nothing to ensure the flow through the metering point where the dynamic signal emanates from ever changes. Additionally, if it belongs in a reliability standard at all, it should be included in a BAL standard."Regarding R4, Seattle adds that it will be almost impossible to determine or prove that the adjusted value was not exceeded as required in Measure 4. An entity could possibly do that positively if it only had one intertie and one interchange schedule.
Response: Thank you for your comment. These requirements allow changes directed by the RC or necessitated by loss of resources to be implemented before submitting an RFI or modifying a Confirmed Interchange for future consideration as part of the congestion management process. **With respect to R4, comments received indicate industry consensus for removing Requirement R4. Industry has commented that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit. The CISDT agrees and has removed R4.**		
SPP Standards Review Group	Yes	Delete 4.2 in the Applicability Section. It is blank. In the 4th bullet of the Background Section, we suggest changing the reference to the ACE value to the ACE equation. The bullet would then read: R4 was created to address the fact that when a Reliability Adjustment Arranged Interchange is approved for a Pseudo-Tie or Dynamic Schedule, action is required by the Balancing Authority to ensure that the data source feeding the Net Interchange value in the ACE equation does not exceed the MW value of the Reliability Adjustment Arranged Interchange. Also we suggest the following wording change for

Organization	Yes or No	Question 4 Comment
		R3: Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of that modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons.
Response: Thank you for your comment. The blank 4.2 in Section A4 has been deleted. **With respect to R4, comments received indicate industry consensus for removing Requirement R4. Industry has commented that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit. The CISDT agrees and has removed R4.** **The SDT notes that your comment on R3 actually applies to R2. We agree with the revision and have revised R2 accordingly.**		
SERC OC Review Group	Yes	The SDT is requested to consider modifying the Reliability Adjustment Arranged Interchange definition. The current definition language is: Reliability Adjustment Arranged Interchange - Request to modify Confirmed Interchange or Implemented Interchange for reliability purposes. Suggested modification follows: DELETE: “Request to modify a” ADD: Modified New definition: Interchange or Implemented Interchange for reliability purposes. The SDT is requested to modify M2 so it is consistent with R2. The current M2 language is:M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was created within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2) Suggested modification to M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was DELETE: “created” REPLACE with: “submitted” within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual

Organization	Yes or No	Question 4 Comment
		or anticipated reliability-related reasons. (R2) The SDT is requested to modify M3 so it is consistent with R3. The current M3 language is: The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a RFI was created reflecting that Interchange schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)Suggested modification to M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a RFI was DELETE: "created" REPLACE with: "submitted" reflecting that Interchange schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)
Response: Thank you for your comment. The CISDT disagrees with your comment about Reliability Adjustment Arranged Interchange. A Reliability Adjustment Arranged Interchange is a request and not the result of an approved request to modify Confirmed Interchange. **The CISDT agrees with your comments on the Measures for R2 and R3 and has modified M2 and M3 accordingly.**		
Dominion NERC Compliance Policy	Yes	Throughout the entire Standard, Pseudo-Tie needs to be corrected to read as Pseudo-tie, as changed in the definition.
Response: Thank you for your comment. The defined term is "Pseudo-Tie," and the CISDT has made this consistent throughout the standard.		
Florida Municipal Power Agency	Yes	Please see FMPA comments to Question 1. The proposed INT-010 is duplicative of BAL standards (e.g., BAL-002) that already cause a BA to balance supply and demand for loss of a generator. This proposed standard simply contains commercial considerations for how such replacement is made and as such is not reliability based. As such, the standard should be retired in accordance with P81 recommendations and the Independent Expert Review Panel recommendations.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment. Requirements R1, R2 and R3 allow changes directed by the RC or necessitated by loss of resources to be implemented before submitting an RFI or modifying a Confirmed Interchange for future consideration as part of the congestion management process. With respect to R4, comments received indicate industry consensus for removing Requirement R4. Industry has commented that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit. The CISDT agrees and has removed R4.</td></tr>
<tr><td>ACES Standards Collaborators</td><td>Yes</td><td>(1) INT-010-2 R4 uses the wrong interchange term. It states that each BA shall ensure the MW level from the Confirmed Interchange for Reliability Adjustment Arranged Interchange is not exceeded for the Dynamic Interchange Schedule or Pseudo-Tie established in the BA’s ACE equation. However, it is the Implemented Interchange state in which the value is supposed to be entered into the ACE equation per the NERC Glossary Definition. Thus, we recommend changing Confirmed Interchange to Implemented Interchange.

(2) INT-010-2 R1 - There is a missing period at the end of the requirement.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1) Comments received indicate industry consensus for removing Requirement R4. Industry has commented that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit. The CISDT agrees and has removed R4.
2) The CISDT has made this correction.</td></tr>
<tr><td>Bonneville Power Administration</td><td>Yes</td><td>o Definitions

o Dynamic Schedule o BPA recommends the drafting team remove the word “time-” from “A time-varying energy transfer that is update . . .” The term time-varying is inaccurate; the amount of energy varies while time does not.

o Requirement 2 BPA requests clarification on how the drafting team expects R2 to be accomplished if the Sink BA is not the Transmission Operator.

o General Considerations for Curtailments of Dynamic Transfers For clarification purposes, BPA recommends revising and moving the first sentence from the For</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>Dynamic Schedule section to above the General Considerations for Curtailments of Dynamic Transfers section. “If Transmission Services between the source and sink BA is curtailed, then the allowable range of the magnitude of the schedules between them must be curtailed accordingly.”

o For Dynamic Schedules: BPA recommends the term curtailment be modified to Reliability Adjustment Arranged Interchange in the For Dynamic Schedules section.

o For Capacity Transactions: BPA recommends the drafting team consider adding the following subsection for Capacity Transactions, similar to the pseudo-tie statement as follows: If transmission services between the sink BA and the source BA are curtailed, then the allowable range of magnitude of the capacity transaction between them must be limited according to these constraints.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The CISDT disagrees with the comment on the definition of Dynamic Schedule, as the term “time-varying” is an adjective relating to the energy transfer.

With respect to R2, the CISDT notes that the BA is responsible for Interchange and that the requirement allows 60 minutes for the Reliability Adjustment Arranged Interchange to be submitted. This allows for communication between and among entities to take actions to maintain reliability and then submit an RAAI.

With respect to your final three comments, the CISDT notes that these three comments apply to the Guidelines and Technical basis of the standard. The CISDT has excerpted sections of the Dynamic Transfer Reference Guidelines here and prefers to leave the language as-is because it is directly quoting that document. The CISDT also does not consider capacity transactions to be Dynamic Transfers.</td></tr>
<tr><td>MRO NERC Standards Review Forum</td><td>Yes</td><td>R2.3 of INT-004 states that the LSE is responsible for maintaining the RFI for Reliability Adjustment requests. If the Pseudo-Ties are implemented through an agreed upon alternate congestion management approach (such as reporting market flows or generation-to-load flows to the IDC), the IDC will assign a relief obligation to the BA. The BA will redispatch its system to meet the relief obligation which may or may not involve a change to the pseudo-tie output. In this instance, it is not appropriate to limit the pseudo-tie output in the ACE equation to a reliability cap if</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
		other generation is being redispatched to meet the relief obligation. Therefore it is recommended this requirement be removed.
Response: Thank you for your comment. Comments received indicate industry consensus for removing Requirement R4. Industry has commented that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit. The CISDT agrees and has removed R4.		
NextEra Energy/Florida Power and Light	Yes	This standard appears to be more directed a correcting a perceived inequity in congestion management procedures and/or in energy sharing agreements for reliability than in promoting or ensuring real-time reliability. R1, R2 and R3 should be retired (using the paragraph 81 criteria), and possibly transferred to NAESB. They do nothing to impact real-time reliability, and could actually adversely impacts reliability if a RFI for reliability fails to get implemented within the arbitrary 60 minute windows specified in these requirements and the energy scheduled for reliability reasons prematurely ends. Additionally, any limitations on how long energy sharing transactions or RC directed schedules for reliability reason should be exempted from standard interchange scheduling processes and procedures should be addressed by NAESB, not NERC. Finally, R4 does not belong in an INT standard. It is unclear how capping the MW value in ACE equations helps ensure reliability. While a cap may change which BA supplies the energy above the MW cap, it does nothing to ensure the flow through the metering point where the dynamic signal emanates from ever changes. Additionally, if it belongs in a reliability standard at all, it should be included in a BAL standard.
Response: Thank you for your comment. Requirements R1, R2 and R3 allow changes directed by the RC or necessitated by loss of resources to be implemented before submitting an RFI or modifying a Confirmed Interchange for future consideration as part of the congestion management process. **With respect to R4, comments received indicate industry consensus for removing Requirement R4. Industry has commented that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit. The CISDT agrees and has**		

Organization	Yes or No	Question 4 Comment
removed R4.		
NIPSCO	Yes	Per MISO recommendation: R2.3 of INT-004 states that the LSE is responsible maintaining the RFI for Reliability Adjustment requests. INT-010 R4 seems to transfer that same activity to the BA role. We request to remove Requirement #4 from INT-010.
Response: Thank you for your comment. Comments received indicate industry consensus for removing Requirement R4. Industry has commented that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit. The CISDT agrees and has removed R4.		
Manitoba Hydro	Yes	(a) M2 and M3 - use the language 'created' instead of 'submitted' as used in the corresponding requirements.
Response: Thank you for your comment. The CISDT has made this correction.		
ReliabilityFirst Corporation	Yes	ReliabilityFirst abstains and offers the following comment for consideration:1. Requirement R1a. ReliabilityFirst requests further clarification on meaning of the term "energy sharing agreement". If this term has a specific meaning that has an impact on the intent of the standard, ReliabilityFirst recommends making it a defined term.
Response: Thank you for your comment. The CISDT has added language to R1, as well as a Rationale box for R1 to provide clarity around "energy sharing agreement." The requirement was modified to read "covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement" (rather than just "covered by an energy sharing agreement") and a rationale was added: **Rationale for R1: This requirement was originally revised to replace the term "request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would**		

Organization	Yes or No	Question 4 Comment
include the applicable conditions under which the energy could be scheduled.		
NorthWestern Energy	Yes	R1 needs more clarification - what does this requirement mean, e.g., what is an energy sharing agreement?
Response: Thank you for your comment. The CISDT has added language to R1, as well as a Rationale box for R1 to provide clarity around "energy sharing agreement." The requirement was modified to read "covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement" (rather than just "covered by an energy sharing agreement") and a rationale was added: Rationale for R1: This requirement was originally revised to replace the term "request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.		
Kansas City Power & Light	Yes	Background Section -4th bullet, I suggest changing the term "ACE value" to the "ACE equation". The bullet would then read:R4 was created to address the fact that when a Reliability Adjustment Arranged Interchange is approved for a Pseudo-Tie or Dynamic Schedule, action is required by the Balancing Authority to ensure that the data source feeding the Net Interchange value in the ACE equation does not exceed the MW value of the Reliability Adjustment Arranged Interchange
Response: Thank you for your comment. R4 has been deleted, so the Background Section information related to it has been as well.		
Seminole Electric Cooperative, Inc.	Yes	R1 should not be qualified / limited to "a loss of resources covered by an energy sharing agreement". Propose the following: ï,§ The Balancing Authority that experiences a loss of a resource or Reliability Adjustment Arranged Interchange, requiring an immediate adjustment to scheduled interchange which will exceed 60 minutes in duration shall ensure that a Request for

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the start time of the event.

Alternately, some effort should be made to clarify the intended meaning of “energy sharing agreement”, the use of which creates considerable ambiguity regarding the requirement and distinction from events NOT “covered by an energy sharing agreement”.

R2 and R3 wording is ambiguous. Propose combining the two into the following:

R2 Upon receiving a directive for a Reliability Adjustment Arranged Interchange to confirmed or implemented Interchange due to actual or anticipated reliability-related reasons, the Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange including the scheduled interchange is submitted within 60 minutes.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The CISDT has added language to R1, as well as a Rationale box for R1 to provide clarity around “energy sharing agreement.” The requirement was modified to read “covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement” (rather than just “covered by an energy sharing agreement”) and a rationale was added:

Rationale for R1: This requirement was originally revised to replace the term “request for an Arranged Interchange” with the defined term “Request for Interchange (RFI)” within the requirement. Additional clarification was requested regarding “energy sharing agreement.” There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

The CISDT believes that combining Requirements R2 and R3 would create more confusion because R2 deals with Reliability Adjustment Arranged Interchange while R3 deals with submitting a new RFI.</td></tr>
<tr><td>Powerex Corp.</td><td>Yes</td><td>Powerex has reviewed the latest draft of the Interchange Standards and considers these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
		important and prevent entities that transact from providing false and misleading information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is implemented in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations. Powerex does not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards. In R1, the term “energy sharing” is not capitalized and thus is open to interpretation, and this leaves the door open for entities to submit RFIs after the scheduling deadlines. In the original INT-010-1, this issue was dealt with by describing the circumstance which this was allowed, specifically “...a loss of resources covered by an energy sharing agreement....”. Either “energy sharing” needs to be defined, or the conditions to allow these modifications should be limited. Powerex suggests reverting back to the current INT-010-1 language use, “...a loss of resources covered by an energy sharing agreement....”.
Response: Thank you for your comment. The CISDT has added language to R1, as well as a Rationale box for R1 to provide clarity around “energy sharing agreement.” The requirement was modified to read “covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement” (rather than just “covered by an energy sharing agreement”) and a rationale was added: **Rationale for R1: This requirement was originally revised to replace the term “request for an Arranged Interchange” with the defined term “Request for Interchange (RFI)” within the requirement. Additional clarification was requested regarding “energy sharing agreement.” There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.**		
PJM Interconnection	Yes	PJM supports the language in R1, R2 and R3. PJM does not support R4, as written, for the following reasons:

Organization	Yes or No	Question 4 Comment
		o It appears that Balancing Authorities have the leeway to take actions in an attempt to remain compliant that simultaneously leave the interconnection worse off. PJM suggests that Balancing Authorities should also be required to coordinate with their Adjacent Balancing Authorities as opposed to only requiring that the values included in their ACE equation never exceed the Confirmed Interchange value. o Further, this requirement makes no allowance for the implementation of a 10-minute straddle ramp without being considered non-compliant, nor does it allow for the physical ramp rates of generators that may be unable to reduce output before the Confirmed Interchange reduction takes effect. o Lastly, INT-004-3 R2 establishes a bandwidth that allows Confirmed Interchange to deviate from actual hourly integrated energy without requiring a tag update. Similarly, the MW value included in an ACE equation should be allowed to deviate from Confirmed Interchange within a certain bandwidth, even when the Confirmed Interchange results from a Reliability Adjustment Arranged Interchange.
Response: Thank you for your comment. Comments received indicate industry consensus for removing Requirement R4. Industry has commented that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit. The CISDT agrees and has removed R4.		

5. **INT-011-1: A requirement was developed to require that each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange unless the information about intra-Balancing Authority transfers is included in congestion management procedure(s) via an alternate method. Do you agree with this proposed requirement? If not, please provide specific suggestions for improvements to the requirement.**

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT did not make any substantive changes to INT-011-1, and it will proceed to final ballot.

Some commenters questioned the necessity of the standard, but the CISDT maintains that it is a reliability issue when flow must be reduced and this is when congestion management procedures apply. All relevant information must be available to know which flows are affecting the system in order to determine which flows must be reduced. While "what" is reduced is an equity / commercial issue, the availability of information for evaluation is a reliability issue. Because of this, and in order to be responsive to the associated FERC directive, the CISDT will retain INT-011-1.

Organization	Yes or No	Question 5 Comment
Seattle City Light	No	Seattle City Light supports that comments of NextEra. Specifically, "This standard appears to be more directed a correcting a perceived inequity in congestion management procedures than in promoting or ensuring real-time reliability. It is also basically an administrative task that does not alter or have any effect on real-time operations, and, thus should be eliminated using the paragraph 81 criteria. If the industry believes congestion management procedures require enhancements related to intra-Balancing Authority Area transfers, there are much more efficient and less burdensome means to achieve this goal than to put in place this reliability standard. For example, NERC could require a LSE to post data related to current-hour schedules for real-time intra-Balancing Authority Area transfers on System Data Exchange (SDX) so that congestion management procedures could have access to such data. Additionally, many BA may have practices that already require entities to submit an RFI related to intra-Balancing Authority Area transfers within or through their BA for energy imbalance calculations and/or for identifying unreserved use. Alternatively, if

Organization	Yes or No	Question 5 Comment
		the drafting team determines a requirement is require for reliability, R1 should be modified to read as follows:R1. Each Load-Serving Entity that uses Point to Point Transmission Service or Network secondary Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange. The phrase “unless the information about intra-Balancing Authority Area transfers is included in congestion management procedure(s) via an alternate method” adds nothing to the requirement. If the sole reason for this requirement is to get data related to intra-Balancing Authority Area transfers into congestion management procedure, the requirement is not needed for reasons stated above."
Response: Thank you for your comment. It is a reliability issue when flow must be reduced and this is when congestion management procedures apply. All relevant information must be available to know which flows are affecting the system in order to determine which flows must be reduced. While “what” is reduced is an equity / commercial issue, the availability of information for evaluation is a reliability issue. The CISDT believes that entities should have the option of using alternative methods to address these transfers in congestion management processes. The CISDT believes that the requirement has achieved stakeholder consensus and that no further revisions are necessary.		
NextEra Energy/Florida Power and Light	No	This standard appears to be more directed a correcting a perceived inequity in congestion management procedures than in promoting or ensuring real-time reliability. It is also basically an administrative task that does not alter or have any effect on real-time operations, and, thus should be eliminated using the paragraph 81 criteria. If the industry believes congestion management procedures require enhancements related to intra-Balancing Authority Area transfers, there are much more efficient and less burdensome means to achieve this goal than to put in place this reliability standard. For example, NERC could require a LSE to post data related to current-hour schedules for real-time intra-Balancing Authority Area transfers on System Data Exchange (SDX) so that congestion management procedures could have access to such data. Additionally, many BA may have practices that already require entities to submit an RFI related to intra-Balancing Authority Area transfers within or through their BA for energy imbalance calculations and/or for identifying unreserved use. Alternatively, if the drafting team determines a requirement is require for

Organization	Yes or No	Question 5 Comment
		reliability, R1 should be modified to read as follows:R1. Each Load-Serving Entity that uses Point to Point Transmission Service or Network secondary Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange. The phrase "unless the information about intra-Balancing Authority Area transfers is included in congestion management procedure(s) via an alternate method" adds nothing to the requirement. If the sole reason for this requirement is to get data related to intra-Balancing Authority Area transfers into congestion management procedure, the requirement is not needed for reasons stated above.
Response: Thank you for your comment. It is a reliability issue when flow must be reduced and this is when congestion management procedures apply. All relevant information must be available to know which flows are affecting the system in order to determine which flows must be reduced. While "what" is reduced is an equity / commercial issue, the availability of information for evaluation is a reliability issue. The CISDT believes that entities should have the option of using alternative methods to address these transfers in congestion management processes. The CISDT believes that the requirement has achieved stakeholder consensus and that no further revisions are necessary.		
American Electric Power	No	AEP sees no reliability benefit to the BES from INT-011-1 and encourage the drafting team to not pursue it.
Response: Thank you for your comment. It is a reliability issue when flow must be reduced and this is when congestion management procedures apply. All relevant information must be available to know which flows are affecting the system in order to determine which flows must be reduced. While "what" is reduced is an equity / commercial issue, the availability of information for evaluation is a reliability issue.		
Florida Municipal Power Agency	No	Please see FMPA comments to Question 1The proposed INT-011 is duplicative of NAESB standards and is commercial in nature. As such, the standard should be retired in accordance with P81 recommendations and the Independent Expert Review Panel recommendations.
Response: Thank you for your comment. It is a reliability issue when flow must be reduced and this is when congestion management procedures apply. All relevant information must be available to know which flows are affecting the system in order		

Organization	Yes or No	Question 5 Comment
to determine which flows must be reduced. While "what" is reduced is an equity / commercial issue, the availability of information for evaluation is a reliability issue.		
Exleon Companies	No	Exelon agrees with comments provided by NextEra for this standard. Addresses congestion management more than reliability. Administrative task that does not alter or have any effect on real-time operations. Alternatively, propose R1 should be modified to read as follows: R1.Each Load-Serving Entity that uses Point to Point Transmission Service or Network secondary Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange.
Response: Thank you for your comment. It is a reliability issue when flow must be reduced and this is when congestion management procedures apply. All relevant information must be available to know which flows are affecting the system in order to determine which flows must be reduced. While "what" is reduced is an equity / commercial issue, the availability of information for evaluation is a reliability issue. The CISDT believes that entities should have the option of using alternative methods to address these transfers in congestion management processes. The CISDT believes that the requirement has achieved stakeholder consensus and that no further revisions are necessary.		
Tacoma Power	No	"Intra-Balancing Authority" is not a defined term and must be fully defined before using the term in a reliability standard.
Response: Thank you for your comment. The CISDT did not create a new term. The use of "intra-Balancing Authority" is meant to include transfers solely within a single Balancing Authority as described in the purpose statement.		
ACES Standards Collaborators	No	(1) INT-011-1 addresses commercial equity issues and is a business practice. RCs, BAs, and TOPs are perfectly capable of working together to re-dispatch generation to address system constraints. The purpose of tagging these intra-BA transactions is to ensure they are included in congestion management procedures such as the IDC so that they are treated equitably with other interchange transactions which is essentially reflected in the purpose statement. While the primary purpose of the IDC is to manage congestion in an equitable fashion, the IDC and WECC USF are not reliability tools because they cannot relieve flows rapidly enough. In fact, FERC

Organization	Yes or No	Question 5 Comment
		recognized this and required NERC to reflect this in the IRO-006 standards. IRO-006-EAST-1 R1 requires the RC to actually implement another action such as re-dispatch besides TLR to mitigate IROL exceedances and violations. Please strike this entire standard.
Response: Thank you for your comment. It is a reliability issue when flow must be reduced and this is when congestion management procedures apply. All relevant information must be available to know which flows are affecting the system in order to determine which flows must be reduced. While "what" is reduced is an equity / commercial issue, the availability of information for evaluation is a reliability issue.		
Northeast Power Coordinating Council	No	
Colorado Spings Utilities	No	
Central Lincoln	No	
NIPSCO	No	
Seminole Electric Cooperative, Inc.	No	
ISO/RTO Standards Review Committee	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern	Yes	

Organization	Yes or No	Question 5 Comment
Company Generation and Energy Marketing		
PacifiCorp	Yes	
SPP Standards Review Group	Yes	
Duke Energy	Yes	
SERC OC Review Group	Yes	
Dominion NERC Compliance Policy	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Powerex Corp.	Yes	

Organization	Yes or No	Question 5 Comment
PJM Interconnection	Yes	

6. **INT-011-1: Do you have any other comments relating to INT-011-1 that you have not previously submitted? Please provide specific suggestions for improvement, including alternate language.**

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT did not make any substantive changes to INT-011-1, and it will proceed to final ballot.

Some commenters questioned the necessity of the standard, but the CISDT maintains that it is a reliability issue when flow must be reduced and this is when congestion management procedures apply. All relevant information must be available to know which flows are affecting the system in order to determine which flows must be reduced. While "what" is reduced is an equity / commercial issue, the availability of information for evaluation is a reliability issue. Because of this, and in order to be responsive to the associated FERC directive, the CISDT will retain INT-011-1.

Organization	Yes or No	Question 6 Comment
Exleon Companies	No	See response to Q 5.
Response: See the CISDT's response to Question 5.		
ISO/RTO Standards Review Committee	No	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	

Organization	Yes or No	Question 6 Comment
PacifiCorp	No	
SPP Standards Review Group	No	
Duke Energy	No	
SERC OC Review Group	No	
Dominion NERC Compliance Policy	No	
Florida Municipal Power Agency	No	
Bonneville Power Administration	No	
MRO NERC Standards Review Forum	No	
Colorado Spings Utilities	No	
American Electric Power	No	
NIPSCO	No	
ReliabilityFirst Corporation	No	
MISO	No	
MidAmerican Energy	No	

Organization	Yes or No	Question 6 Comment
Kansas City Power & Light	No	
Seminole Electric Cooperative, Inc.	No	
PJM Interconnection	No	
Seattle City Light	Yes	For this draft to proceed, Seattle City Light requests that the term "intra-Balancing Authority Area transfer" be defined (in addition to the changes suggested by NextEra as indicated in Question 5).
Response: Thank you for your comment. The use of "intra-Balancing Authority" is meant to include transfers solely within a single Balancing Authority as described in the purpose statement.		
Central Lincoln	Yes	Suggest changing "4.1.1. Load-Serving Entities" to "4.1.1. Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers." This better matches the trend to more explicitly state the applicability within the applicability section.
Response: Thank you for your comment. The CISDT does not believe this revision is necessary or adds clarity to the standard.		
Powerex Corp.	Yes	Powerex has reviewed the latest draft of the Interchange Standards and considers these standards a necessity for reliable operations of the Bulk Electric System. The Interchange Standards provide the appropriate validation and verification of the interchange schedules prior to implementation. The Interchange Standards are important and prevent entities that transact from providing false and misleading information to reliability entities, which minimize impacts to the operation of the BES. The Interchange Standards also require that adjacent Balancing Authorities agree upon the magnitude and ramping of the interchange before it is implemented in the ACE equations in order to avoid the imbalance and inadvertent in the Interconnection. This allows for efficient and more reliable operations. Powerex does

Organization	Yes or No	Question 6 Comment
		not believe that any of the requirements of the Interchange Standards should be removed or moved to the NAESB business practice standards.
Response: Thank you for your support.		
Texas Reliability Entity	Yes	1. These INT standards in general, and INT-011 in particular, do not appear to apply to intra-Balancing Authority Area transfers in the ERCOT region. Consider expressly excluding such transfers from the applicability of these standards in order to avoid future misunderstandings.
Response: Thank you for your comment. When the drafting team reviewed the requirements we did not see that an exemption is required. For example, on INT-011, if ERCOT does not have point-to-point service, the requirement would not apply and an exemption is not needed. However, when we look at INT-006, if ERCOT is involved in a transaction outside its area, all of these requirements would apply.		
City of Austin dba Austin Energy	Yes	City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: See response to Seattle City Light.		
Manitoba Hydro	Yes	

7. Definitions: The CISDT proposed revisions to the defined term Dynamic Schedule. Do you agree with the proposed revisions? If not, please provide specific suggestions for improvements.

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT has corrected typos in the definition of Dynamic Schedule, but has otherwise not changed it. It will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 7 Comment
SPP Standards Review Group	No	Change 'real time' to 'Real-time' since it is NERC Glossary Term.
Response: Thank you for your comment. The CISDT has made this revision.		
Florida Municipal Power Agency	No	Since these are commercial definitions and not reliability based, the NAESB definitions should be used and no attempt to define it differently should be made. See WEQ-000 for NAESB definition.
Response: Thank you for your comment. The CISDT notes that many of these definitions are currently in the NERC Glossary of Terms and the team believes that these are necessary for the standards.		
Exleon Companies	No	See response to INT-009 question.
Response: See response to INT-009 comment.		
ACES Standards Collaborators	No	(1) "Net Interchange Scheduled" should be "Net Interchange Schedule" to match the definition in the NERC Glossary of Terms. There is an extra "d" at the end of the term. (2) There is no need to include the clause "that is updated in real time" in the

Organization	Yes or No	Question 7 Comment
		definition. It only makes the definition longer, more confusing and could lead to ambiguity. Stating that it is updated in real-time implies that someone is actually taking action to update the schedule which is contrary to what is happening because the schedule is updated in the ACE equation automatically as the telemetered value changes. The description of a time-varying energy transfer is sufficiently clear and succinct to avoid ambiguity. Furthermore, if the energy transfer is time-varying it would change real-time.
Response: Thank you for your comments. **1) The CISDT has corrected this error.** **2) The CISDT does not believe that the propose definition is verbose. Stakeholder consensus for the definition has been achieved with regard to this definition and no change was made.**		
Colorado Spings Utilities	No	
ReliabilityFirst Corporation	No	
Kansas City Power & Light	Yes	Typo - need to capitalize Real-time
Response: Thank you for your comment. The CISDT has corrected this error.		
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Please see the response to Seattle City Light.		
ISO/RTO Standards Review Committee	Yes	
Southern Company: Alabama Power Company; Georgia	Yes	

Organization	Yes or No	Question 7 Comment
Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
PacifiCorp	Yes	
Duke Energy	Yes	
SERC OC Review Group	Yes	
Dominion NERC Compliance Policy	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
NIPSCO	Yes	
Manitoba Hydro	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Seminole Electric Cooperative,	Yes	

Organization	Yes or No	Question 7 Comment
Inc.		
Powerex Corp.	Yes	
PJM Interconnection	Yes	

8. **Definitions: The CISDT proposed revisions to the defined term Pseudo-Tie. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.**

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT has corrected a typo and made a clarifying change to the definition of Pseudo-Tie, but has otherwise not changed it. It will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 8 Comment
SPP Standards Review Group	No	Change 'real time' to 'Real-time' since it is NERC Glossary Term.
Response: Thank you. The CISDT has corrected this error.		
SERC OC Review Group	No	The SDT is respectfully requested to clarify that a Pseudo-Tie is not a physical tie that actually exists.
Response: The CISDT notes that a Pseudo-Tie is not a physical tie that actually exists.		
Exleon Companies	No	See response to INT-009 question.
Response: See response to those comments.		
Florida Municipal Power Agency	No	Since these are commercial definitions and not reliability based, the NAESB definitions should be used and no attempt to define it differently should be made. See WEQ-000 for NAESB definition.
Response: Thank you for your comment. The CISDT notes that many of these definitions are currently in the NERC Glossary of Terms and the team believes that these are necessary for the standards.		
ACES Standards Collaborators	No	(1) "Net Interchange Actual" should be "Net Actual Interchange". The former is not

Organization	Yes or No	Question 8 Comment
		in the NERC Glossary of Terms. (2)There is no need to include the clause “that is updated in real time” in the definition. It only makes the definition longer, more confusing and could lead to ambiguity. Stating that it is updated in real-time implies that someone is actually taking action to update the schedule which is contrary to what is happening because the schedule is updated in the ACE equation as the telemetered value changes. The description of a time-varying energy transfer is sufficiently clear and succinct to avoid ambiguity. Furthermore, if the energy transfer is time-varying it would change real-time.
Response: Thank you for your comments. **1) The correct term is Net Actual Interchange as those relates to ACE. We have added notation (NI_A) to the definition for clarification.** **2) The CISDT does not believe that the proposed definition is verbose and believes that stakeholder consensus has been achieved with regard to this definition.**		
Colorado Spings Utilities	No	
Duke Energy	Yes	Duke Energy recommends revising the definition as follows: “Pseudo-tie: A time-varying energy transfer that is updated in real time and included in the Net Interchange Actual term in the same manner as a Tie Line in the affected Balancing Authorities’ control ACE equations (or alternate control processes), but for which no physical tie or energy metering actually exists.”
Response: The CISDT thanks you for the proposed revision but we believe that stakeholder consensus has been achieved with regard to this definition.		
Dominion NERC Compliance Policy	Yes	Dominion suggests in the Implementation Plan that Pseudo-Tie should be corrected to read as Pseudo-tie (as changed in the definition).

Organization	Yes or No	Question 8 Comment
Response: The existing term is Pseudo-Tie and the CISDT has made this consistent throughout its documents.		
Kansas City Power & Light	Yes	Typo - need to capitalize Real-time
Response: Thank you. This correction has been made.		
PJM Interconnection	Yes	PJM supports the revisions to the Pseudo Tie definition and recommends further modification of the definition to include reference that Pseudo Tied generation should be properly accounted for in a Balancing Authority's load calculation. The Native Balancing Authority must exclude that generation from their internal load calculation and the Attaining Balancing Authority must include that generation in their internal load calculation.
Response: The CISDT thanks you for the proposed revision but we believe that stakeholder consensus has been achieved with regard to this definition.		
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: See response to Seattle City Light.		
Northeast Power Coordinating Council	Yes	
ISO/RTO Standards Review Committee	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power	Yes	

Organization	Yes or No	Question 8 Comment
Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
NIPSCO	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Powerex Corp.	Yes	

9. **Definitions: The CISDT proposed revisions to the defined term Adjacent Balancing Authority. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.**

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT has corrected a typo in the definition of Adjacent Balancing Authority, but has otherwise not changed it. It will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 9 Comment
ISO/RTO Standards Review Committee	No	Comments: Remove the first "Area" in the sentence and add the phrase "within an Interconnection": A Balancing Authority Area whose Balancing Authority Area that is interconnected within an Interconnection with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Response: Thank you for your comment. This error was contained in the redline version only. The clean version in the Implementation Plan was correct as you noted.		
ACES Standards Collaborators	No	(1) There are multiple definitions posted with slight variations. The definition as stated in INT-006 states that it is a "Balancing Authority Area whose Balancing Authority Area". There is an extra Area in the definition. The definition as written in the implementation plan correctly does not include the first "Area". However, it does include "that" which was struck in INT-006. These definitions need to be aligned. We believe the definition should be "A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff".
Response: Thank you for your comment. This error (additional Area) was contained in the redline version only. The clean version in the Implementation Plan was correct as you noted. We have also aligned the Implementation Plan with the standard by		

Organization	Yes or No	Question 9 Comment
removing "that" as you suggested.		
Colorado Spings Utilities	No	
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Please see response to those comments.		
Northeast Power Coordinating Council	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
SPP Standards Review Group	Yes	
Duke Energy	Yes	
SERC OC Review Group	Yes	
Dominion NERC Compliance Policy	Yes	

Organization	Yes or No	Question 9 Comment
Florida Municipal Power Agency	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
NIPSCO	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Powerex Corp.	Yes	
PJM Interconnection	Yes	

10. Definitions: The CISDT proposed revisions to the defined term Arranged Interchange. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

Summary Consideration:

The CISDT thanks all stakeholders for their feedback. Based on stakeholder feedback, the definition has been simplified to read, “The state where a Request for Interchange (initial or revised) has been submitted for approval.”

Organization	Yes or No	Question 10 Comment
ISO/RTO Standards Review Committee	No	Comments: If Sink distribution requirements are going away, why define the Sink as the recipient in this definition. The Sink was removed from Confirmed definition. Proposal: The state where a Request for Interchange or intra-Balancing Authority transfer information (initial or revised) have been submitted for approval from applicable entities. An Arranged Interchange marks the beginning of the Requirement Timing Assessment Period as defined in INT-006.
Response: Thank you for your comment. Based on stakeholder feedback, the definition has been simplified to read, “The state where a Request for Interchange (initial or revised) has been submitted for approval.”		
Florida Municipal Power Agency	No	Since these are commercial definitions and not reliability based, the NAESB definitions should be used and no attempt to define it differently should be made. See WEQ-000 for NAESB definition.
Response: Thank you for your comment. The CISDT notes that many of these definitions a currently in the NERFC Glossary of Terms and the team believes that these are necessary for the standards.		
ACES Standards Collaborators	No	(1) Since we believe that tagging of intra-BA schedules is performed for commercial and equity reasons and belongs in a business practice and not a standard, we do not support adding intra-BA scheduling to the definition. Reliability standards and

Organization	Yes or No	Question 10 Comment
		corresponding definitions should not focus on market activities or interactions, as they do not relate to reliability of the Bulk Electric System.
Response: Thank you for your comment. Based on stakeholder feedback, the definition has been simplified to read, "The state where a Request for Interchange (initial or revised) has been submitted for approval."		
Colorado Spings Utilities	No	
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Thank you for your comments. Please see the response to Seattle City Light's comments.		
Northeast Power Coordinating Council	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
SPP Standards Review Group	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 10 Comment
SERC OC Review Group	Yes	
Dominion NERC Compliance Policy	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
NIPSCO	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Powerex Corp.	Yes	

Organization	Yes or No	Question 10 Comment
PJM Interconnection	Yes	

11. Definitions: The CISDT proposed revisions to the defined term Confirmed Interchange. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT has made no changes to the definition of Confirmed Interchange and it will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 11 Comment
Florida Municipal Power Agency	No	Since these are commercial definitions and not reliability based, the NAESB definitions should be used and no attempt to define it differently should be made. See WEQ-000 for NAESB definition.
Response: Thank you for your comment. The CISDT notes that many of these definitions are currently in the NERC Glossary of Terms and the team believes that these are necessary for the standards.		
ACES Standards Collaborators	No	(1) The definition should be simplified. Arranged Interchange can only become Confirmed Interchange once all required parties have approved it. Thus, there is no need to mention anything about parties not approving the interchange because it would not meet the definition. If a transaction is an Arranged Interchange, by definition, all required parties have approved it. Thus, please strike “no party has denied and”.
Response: Thank you for your comment. There are certain PSEs that have denial rights but not approval responsibilities. Therefore, the CISDT will retain the original language.		
Colorado Spings Utilities	No	
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light’s comments on this standard.

Organization	Yes or No	Question 11 Comment
Response: Please see the responses to those comments.		
Northeast Power Coordinating Council	Yes	
ISO/RTO Standards Review Committee	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
SPP Standards Review Group	Yes	
Duke Energy	Yes	
SERC OC Review Group	Yes	
Dominion NERC Compliance Policy	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 11 Comment
MRO NERC Standards Review Forum	Yes	
NIPSCO	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Powerex Corp.	Yes	
PJM Interconnection	Yes	

12. Definitions: The CISDT proposed revisions to the defined term Intermediate Balancing Authority. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT has made no changes to the definition of Intermediate Balancing Authority and it will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 12 Comment
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Please see the responses to Seattle City Light.		
Colorado Spings Utilities	No	
Northeast Power Coordinating Council	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
SPP Standards Review Group	Yes	

Organization	Yes or No	Question 12 Comment
Duke Energy	Yes	
SERC OC Review Group	Yes	
Dominion NERC Compliance Policy	Yes	
ACES Standards Collaborators	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
NIPSCO	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
Seminole Electric Cooperative,	Yes	

Organization	Yes or No	Question 12 Comment
Inc.		
Powerex Corp.	Yes	
PJM Interconnection	Yes	

13. Definitions: The CISDT proposed revisions to the defined term Request for Interchange (RFI). Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

Summary Consideration:

The CISDT thanks all commenters for their comments. Based on stakeholder feedback, the CISDT has revised the proposed definition to: "A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority."

Organization	Yes or No	Question 13 Comment
ISO/RTO Standards Review Committee	No	Comments: As there are no requirements for distribution, nor does this definition supply where the request is coming from, the definition does not also have to define the Sink BA as the recipient of the request. Proposed: A collection of data as defined in the NAESB Business Practice Standards ~~RFI Datasheet~~, to be submitted ~~to the Interchange Sink Balancing Authority for the purpose of collecting approvals~~ for the implementation of bilateral Interchange between a Source and Sink Balancing Authority or energy transfer within a single Balancing Authority.
Response: Thank you for your comment. Based on stakeholder feedback, the CISDT has revised the proposed definition to: "A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority."		
Florida Municipal Power Agency	No	Since these are commercial definitions and not reliability based, the NAESB definitions should be used and no attempt to define it differently should be made. See WEQ-000 for NAESB definition.
Response: Thank you for your feedback. The CISDT notes that many of these definitions are currently in the NERC Glossary of Terms and the team believes that these are necessary for the standards.		

Organization	Yes or No	Question 13 Comment
ACES Standards Collaborators	No	(1) By definition in the NERC Glossary, Interchange is an energy transfer that crosses BA boundaries. The proposed definition of Request for Interchange states that a bilateral Interchange may be within a single BA. This conflicts with the definition of Interchange.
Response: Thank you for your comment. Based on stakeholder feedback, the CISDT has revised the proposed definition to: "A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority."		
Colorado Spings Utilities	No	
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Thank you. Please see the response to Seattle City Light.		
Northeast Power Coordinating Council	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
SPP Standards Review Group	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 13 Comment
SERC OC Review Group	Yes	
Dominion NERC Compliance Policy	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
NIPSCO	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Powerex Corp.	Yes	

Organization	Yes or No	Question 13 Comment
PJM Interconnection	Yes	

14. **Definitions: The CISDT proposed revisions to the defined term Sink Balancing Authority. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.**

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT has corrected a typo in the definition of Sink Balancing Authority, but has otherwise not changed it. It will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 14 Comment
ISO/RTO Standards Review Committee	No	There will also be a Sink BA for Interchange Transactions that do not require an Interchange Schedule. Recommend that the phrase “and the resulting Interchange Schedule” be deleted.
Response: Thank you for your comment. We have revised the language to indicate “any resulting Interchange Schedule” to address your concern.		
Florida Municipal Power Agency	No	Since these are commercial definitions and not reliability based, the NAESB definitions should be used and no attempt to define it differently should be made. See WEQ-000 for NAESB definition.
Response: Thank you for your comment. The CISDT notes that many of these definitions are currently in the NERC Glossary of Terms and the team believes that these are necessary for the standards.		
Colorado Spings Utilities	No	
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light’s comments on this standard.
Response: Please see the response to Seattle City Light.		
Northeast Power Coordinating	Yes	

Organization	Yes or No	Question 14 Comment
Council		
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
SPP Standards Review Group	Yes	
Duke Energy	Yes	
SERC OC Review Group	Yes	
Dominion NERC Compliance Policy	Yes	
ACES Standards Collaborators	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
NIPSCO	Yes	

Organization	Yes or No	Question 14 Comment
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Powerex Corp.	Yes	
PJM Interconnection	Yes	

15. Definitions: The CISDT proposed revisions to the defined term Source Balancing Authority. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT has corrected a typo in the definition of Source Balancing Authority, but has otherwise not changed it. It will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 15 Comment
ISO/RTO Standards Review Committee	No	There will also be a Source BA for Interchange Transactions that do not require an Interchange Schedule. "IS" reference should be removed.
Response: Thank you for your comment. We have revised the language to indicate "any resulting Interchange Schedule" to address your concern.		
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Please see the response to Seattle City Light.		
Florida Municipal Power Agency	No	Since these are commercial definitions and not reliability based, the NAESB definitions should be used and no attempt to define it differently should be made. See WEQ-000 for NAESB definition.
Response: Thank you for your comment. The CISDT notes that many of these definitions are currently in the NERC Glossary of Terms and the team believes that these are necessary for the standards.		

Organization	Yes or No	Question 15 Comment
Colorado Spings Utilities	No	
Northeast Power Coordinating Council	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
SPP Standards Review Group	Yes	
Duke Energy	Yes	
SERC OC Review Group	Yes	
Dominion NERC Compliance Policy	Yes	
ACES Standards Collaborators	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review	Yes	

Organization	Yes or No	Question 15 Comment
Forum		
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Powerex Corp.	Yes	
PJM Interconnection	Yes	

16. **Definitions: The CISDT proposed a new defined term, Reliability Adjustment Arranged Interchange which is a replacement for the current term Reliability Adjustment RFI. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.**

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT has corrected a typo in the definition of Reliability Adjustment Arranged Interchange, but has otherwise not changed it. It will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 16 Comment
SPP Standards Review Group	No	We suggest the following change to the definition of Reliability Adjustment Arranged Interchange: A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
Response: Thank you for your comment. We have added "A" to the beginning of the definition as requested.		
SERC OC Review Group	No	The SDT is requested to consider modifying the Reliability Adjustment Arranged Interchange definition. The current definition language is: Reliability Adjustment Arranged Interchange - Request to modify Confirmed Interchange or Implemented Interchange for reliability purposes. Suggested modification follows: DELETE: "Request to modify a" ADD: Modified New definition: Modified Confirmed Interchange or Implemented Interchange for reliability purposes.
Response: Thank you for your comment. The CISDT disagrees as a Reliability Adjustment Arranged Interchange is a request and not the result of an approved request to modify Confirmed Interchange.		
ACES Standards Collaborators	No	(1) First, contrary to the name of the term, it is not actually Interchange but rather a request to modify Confirmed Interchange or Implemented Interchange. The

Organization	Yes or No	Question 16 Comment
		name implies it is Interchange and this may cause confusion. (2) The name of the definition implies it is a type of Arranged Interchange which leads to confusion when reading INT-010 R2. Arranged Interchange is the state in which the sink BA has received Interchange information. Thus, if a reader assumes that Reliability Adjustment Arranged Interchange is a type of Arranged Interchange, INT-010 R2 becomes circular because it requires the Sink BA to ensure that Arranged Interchange is submitted which ultimately goes to the Sink BA by the definition of Arranged Interchange. Simply changing the name of Reliability Adjustment Arranged Interchange will avoid much of this confusion.
Response: Thank you for your comment. The CISDT believes that this is the correct term because a revision to any Confirmed Interchange or Implemented Interchange is an Arranged Interchange.		
Colorado Spings Utilities	No	
PJM Interconnection	Yes	PJM supports the new term Reliability Adjustment Arranged Interchange , but asks the drafting team to formally comment on the difference between this new definition and the existing definition Reliability Adjustment RFI and why it is necessary to replace the current term. This explanation was not apparent in the materials posted for review.
Response: Thank you for your comment. The CISDT changed this from RFI to Arranged Interchange because a revision to any Confirmed Interchange or Implemented Interchange is an Arranged Interchange and RFI is a new request for Interchange.		
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Please see the response to Seattle City Light.		
Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 16 Comment
ISO/RTO Standards Review Committee	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
Dominion NERC Compliance Policy	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	

Organization	Yes or No	Question 16 Comment
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	

17. **Definitions: The CISDT proposed a new defined term Composite Confirmed Interchange. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.**

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT has made no changes to the definition of Composite Confirmed Interchange and it will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 17 Comment
PacifiCorp	No	See PacifiCorp's comments under INT-009 (above).
Response: Please see our response to the comments under INT-009 above.		
ACES Standards Collaborators	No	(1) Because INT-009 R1 is redundant with BAL-006 R4 and this is the only use of Composite Confirmed Interchange, we cannot support the definition. The requirement is unnecessary and obviates the need for the definition. (2) The Composite Confirmed Interchange definition is not clear. The definition could be the total aggregate Confirmed Interchange for a given BA or between BAs. Is it intended to have this flexibility? Since the definition is not limited to a single BA or any specific number of BAs, it could be interpreted as the aggregate of all Confirmed Interchange in an Interconnection which would be whatever Interchange is flowing across the DC ties. We recommend adding more details to the definition for clarity.
Response: Thank you for your comment. **1) The CISDT does not believe that INT-009 R1 is redundant. BAL-006 R4 does not have an exclusion for dynamic schedules and does not have an inclusion for INT-010 R1-R3.** **2) The CISDT thanks you for the proposed revision but believes that stakeholder consensus has been achieved with respect to this definition.**		

Organization	Yes or No	Question 17 Comment
Colorado Spings Utilities	No	
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Please see the response to Seattle City Light.		
Northeast Power Coordinating Council	Yes	
ISO/RTO Standards Review Committee	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
SPP Standards Review Group	Yes	
Duke Energy	Yes	
SERC OC Review Group	Yes	
Dominion NERC Compliance Policy	Yes	

Organization	Yes or No	Question 17 Comment
Florida Municipal Power Agency	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
Powerex Corp.	Yes	
PJM Interconnection	Yes	

18. Definitions: The CISDT proposed a new defined term Attaining Balancing Authority. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT has corrected typos in the definition of Attaining Balancing Authority, but has otherwise not changed it. It will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 18 Comment
ISO/RTO Standards Review Committee	No	Recommend revising the definition to add the phrase “within an Interconnection” at the end of the definition.
Response: The CISDT thanks you for the proposed revision but believes that stakeholder consensus has been achieved with respect to this definition.		
Duke Energy	No	Duke Energy questions why Attaining BA was used instead of Sink BA. They appear to have the same meaning.
Response: Thank you for your comment. This definition is used to align more with the terms used in the NAESB standards.		
ACES Standards Collaborators	No	We suggest that “dynamic transfer” should be changed to Pseudo-Tie in the definition for clarity. After all, it is a Pseudo-Tie that changes the metered boundaries of the Balancing Authority Area. We also suggest changing “effective control boundaries” to “Balancing Authority Area” for clarity. BAA is the correct term and is more clear.
Response: Thank you for your comment. We have changed this term to “Dynamic Transfer” which includes both Dynamic Schedules and Pseudo-Ties.		

Organization	Yes or No	Question 18 Comment
American Electric Power	No	Please see our response to Question 1.
Response: Please see the CISDT's response to Question 1.		
Colorado Spings Utilities	No	
Northeast Power Coordinating Council	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
SPP Standards Review Group	Yes	
SERC OC Review Group	Yes	
Dominion NERC Compliance Policy	Yes	
Florida Municipal Power Agency	Yes	
Bonneville Power	Yes	

Organization	Yes or No	Question 18 Comment
Administration		
MRO NERC Standards Review Forum	Yes	
PJM Interconnection	Yes	PJM supports the new term but asks the drafting team to formally comment on the rationale as to how this definition is materially different from the term Sink Balancing Authority and why it is necessary.
Response: Thank you for your comment. This definition is used to align more with the terms used in the NAESB standards.		
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Please see the response to Seattle City Light.		

19. Definitions: The CISDT proposed a new defined term Native Balancing Area. Do you agree with the proposed definition? If not, please provide specific suggestions for improvements.

Summary Consideration:

The CISDT thanks all commenters for their feedback. The CISDT has corrected typos in the definition of Native Balancing Area, but has otherwise not changed it. It will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 19 Comment
Duke Energy	No	Duke Energy questions why Native BA was used instead of Source BA. They appear to have the same meaning.
Response: Thank you for your comment. This definition is used to align more with the terms used in the NAESB standards.		
ACES Standards Collaborators	No	We suggest that "dynamic transfer" should be changed to Pseudo-Tie in the definition for clarity. After all, it is a Pseudo-Tie that changes the metered boundaries of the Balancing Authority Area. We also suggest changing "effective control boundaries" to "Balancing Authority Area" for clarity. BAA is the correct term and is more clear.
Response: Thank you for your comment. We have changed this term to "Dynamic Transfer" which includes both Dynamic Schedules and Pseudo-Ties.		
American Electric Power	No	Please see our response to Question 1.
Response: Please see the CISDT's response to Question 1.		
Colorado Spings Utilities	No	
PJM Interconnection	Yes	PJM assumes this question is specific to the new defined term Native Balancing Authority not Area. PJM supports the new term but asks the drafting team to

Organization	Yes or No	Question 19 Comment
		formally comment on the rationale as to how this definition is materially different from the term Source Balancing Authority and why it is necessary.
Response: Thank you for your comment. This definition is used to align more with the terms used in the NAESB standards.		
ISO/RTO Standards Review Committee	Yes	Recommend revising the definition to add the phrase "within an Interconnection" at the end of the definition.
Response: The CISDT thanks you for the proposed revision but believes that stakeholder consensus has been achieved with respect to this definition.		
Northeast Power Coordinating Council	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
SPP Standards Review Group	Yes	
SERC OC Review Group	Yes	
Dominion NERC Compliance Policy	Yes	

Organization	Yes or No	Question 19 Comment
Florida Municipal Power Agency	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
Powerex Corp.	Yes	
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: See the response to Seattle City Light.		

20. **FERC Directives from Order 693, Paragraph 866: The CISDT has proposed revisions to the definition of Operational Planning Analysis. Do you agree with this proposed defined term? If not, please provide specific substantive suggestions for improvements to the definitions.**

Summary Consideration: The CISDT thanks all commenters for their feedback. The CISDT has made no changes to the definition of Operational Planning Analysis and it will proceed to final ballot. Individual comments are addressed below.

Organization	Yes or No	Question 20 Comment
Duke Energy	No	Duke Energy recommends revising the definition as follows, “Operational Planning Analysis: An analysis of the expected system conditions for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as but not limited to load forecast(s), generation output levels, expected Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). “
Response: The CISDT thanks you for the proposed revision but believes that stakeholder consensus has been achieved with respect to this definition.		
Dominion NERC Compliance Policy	No	While we can support the proposed revision to the term Operational Planning Analysis, for the reasons provided by SDT, we can do so only if corresponding changes are made to the term Real-time Assessment. We believe that Interchange needs to be in both definitions or neither definition. We also suggest that SDT consider revising the SAR and/or the Implementation Plans to more explicitly indicate that they are proposing revisions to the defined terms Operational Planning Analysis and Real-time Assessment which are used in (identify all standards where these terms are used).
Response: Thank you for your comment. The CISDT considered adding the term “Interchange” to “Real-time Assessment” but declined to include it. Real-time Assessments are performed using Real-time information and flows which inherently includes the impacts of Interchange.		

Organization	Yes or No	Question 20 Comment
Colorado Spings Utilities	No	
PJM Interconnection	No	PJM was unable to find mention of this revised term in the materials posted for comment.
Response: We are sorry that you were unable to find this information. It was included in the Comment Form.		
ACES Standards Collaborators	Yes	While we believe the proposed modification to the definition of OPA is unnecessary and provides no additional clarification for what is required, we can support the change if it addresses a FERC concern. We ultimately believe the change is unnecessary because the definition includes expected generation output levels. How could expected generation output levels not include the impact of Interchange? Interchange is implicitly included.
Response: This revision is based on a FERC directive to "*require reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively.*" Based on feedback from the NERC Operating Committee as well as team input, the proposed equally efficient and effective method addresses the directive by revising an existing, approved term contained in the NERC Glossary of Terms.		
Northeast Power Coordinating Council	Yes	
ISO/RTO Standards Review Committee	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern	Yes	

Organization	Yes or No	Question 20 Comment
Company Generation and Energy Marketing		
PacifiCorp	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
City of Austin dba Austin Energy		City of Austin dba Austin Energy (AE) supports Seattle City Light's comments on this standard.
Response: Please see the response to Seattle City Light.		

21. VRFs and VSLs for INT-004-3: The CISDT has proposed Violation Risk Factors and Violation Severity Levels for this standard. Do you agree with these compliance elements? If not, please provide specific substantive suggestions for improvements to the VRFs or VSLs.

Summary Consideration:

The SDT thanks all commenters who submitted feedback on the VRFs and VSLs. Per stakeholder comments, the SDT modified the VSLs for INT-004-3 R1, R2, and R3, INT-006-4 R1, R2, and R5, INT-009-2 R1, and INT-010-2 R1 and R2 to ensure that the VSL language is consistent with the language in the respective requirements. Some commenters questioned the Severe VSLs assigned to many requirements, and the SDT reminds these commenters that VRFs measure the impact to reliability of violating a specific requirement and VSLs measure the degree to which a standard was violated. A standard can have a Lower VRF, because violating it would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, and still have Severe VSL, indicating that the requirement is pass/fail. As the VSL Guidelines state, "If the required performance cannot be broken down to categorize degrees of noncompliant performance that at least partially meet the reliability objective of the requirement, any noncompliance with the requirement will have only one VSL – Severe."

Organization	Yes or No	Question 21 Comment
ISO/RTO Standards Review Committee	No	Under the VRF justifications language, it is stated that: A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Why then are there no lower VSLs under severe? Propose a tiered VSL level for operational impact.
Response: Thank you for your comment. VRFs measure the impact to reliability of violating a specific requirement. VSLs measure the degree to which a standard was violated. A standard can have a Lower VRF, because violating it would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, and still have Severe VSL, indicating that the requirement is pass/fail. As the VSL Guidelines state, "If the required performance cannot be broken down to categorize degrees		

Organization	Yes or No	Question 21 Comment
of noncompliant performance that at least partially meet the reliability objective of the requirement, any noncompliance with the requirement will have only one VSL – Severe."		
SPP Standards Review Group	No	We suggest the Severe VSL for R1 be changed to read:'The Load-Serving Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie but did not ensure that a Request for Interchange...'
Response: Thank you for your comment. As suggested, the CISDT has added "but" before "…did not ensure."		
SERC OC Review Group	No	In the Table of Compliance, R2 the current draft language is: A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours Suggested addition to Table of Compliance, R2 to make the Severe VSL consistent to the requirements: A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours ADD: is expected to persist.
Response: Thank you for your comment. The CISDT has made the suggested change to ensure that the VSL is consistent with the requirement language.		
ACES Standards Collaborators	No	(1) The VSL for R2 is inconsistent with the requirement. The requirement states that the Confirmed Interchange associated with the Dynamic Schedule must be updated if the deviation is expected to persist. However, the VSL mentions nothing about the persistence of the deviation. From reading the VSL, one might conclude that the Confirmed Interchange is required to be updated even if the deviation is not expected to persist which is contrary to the requirement. (2) Because R3 is a business practice and should not be a requirement, we cannot support the VRF for this requirement. The requirement should be struck.
Response: Thank you for your comment. The CISDT has added "…and was expected to persist" to the VSL for R2 to ensure		

Organization	Yes or No	Question 21 Comment
consistency with the requirement language. The CISDT continues to believe that R3 will be necessary for transparency, ensuring proper modeling by all impacted entities and proper coordination with the NAESB Electric Industry Registry publication.		
Colorado Spings Utilities	No	
Northeast Power Coordinating Council	Yes	
Manitoba Hydro	Yes	(a) VSLs, R1, seems to be missing the word 'but' after the word 'Pseudo-tie'
Response: Thank you for your comment. The CISDT has added the "but."		
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	The VSL for INT-004-3 R2 states, "A deviation met or exceeded the criteria in Requirement R2 Parts2.1- 2.3, but the Load-Serving Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours." The reference to future hours, as written, does not have a defined time duration. One suggestion for the duration is current hours plus 2 hours. It is suggested that the VSL for Requirement 3 should have "Attaining" in front of Balancing Authority to correspond to the language of the Requirement.
Response: Thank you for your comment. The VSL mirrors the requirement language.		
PacifiCorp	Yes	
Duke Energy	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review	Yes	

Organization	Yes or No	Question 21 Comment
Forum		
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
PJM Interconnection	Yes	

22. VRFs and VSLs for INT-006-4: The CISDT has proposed Violation Risk Factors and Violation Severity Levels for this standard. Do you agree with these compliance elements? If not, please provide specific substantive suggestions for improvements to the VRFs or VSLs.

Summary Consideration:

The SDT thanks all commenters who submitted feedback on the VRFs and VSLs. Per stakeholder comments, the SDT modified the VSLs for INT-004-3 R1, R2, and R3, INT-006-4 R1, R2, and R5, INT-009-2 R1, and INT-010-2 R1 and R2 to ensure that the VSL language is consistent with the language in the respective requirements. Some commenters questioned the Severe VSLs assigned to many requirements, and the SDT reminds these commenters that VRFs measure the impact to reliability of violating a specific requirement and VSLs measure the degree to which a standard was violated. A standard can have a Lower VRF, because violating it would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, and still have Severe VSL, indicating that the requirement is pass/fail. As the VSL Guidelines state, "If the required performance cannot be broken down to categorize degrees of noncompliant performance that at least partially meet the reliability objective of the requirement, any noncompliance with the requirement will have only one VSL – Severe."

Organization	Yes or No	Question 22 Comment
Northeast Power Coordinating Council	No	In Section B1.2 - Evidence Retention, R2 in the first bullet should read R3, the R3 in the next bullet should read R2 since R3 applies to BA while R2 applies to the TSP.
Response: Thank you for your comment and for catching this error. It has been corrected.		
Independent Electricity System Operator	No	In Section B1.2 - Evidence Retention, we believe the R2 in the first bullet should read R3, whereas the R3 in the next bullet should read R2 since R3 applies to BA while R2 applies to the TSP.
Response: Thank you for your comment and for catching this error. It has been corrected.		
Texas Reliability Entity	No	1. Requirement R1 VSL: Need to add language to cover the "curtail Confirmed

Organization	Yes or No	Question 22 Comment
		Interchange" concept from the requirement. 2. Requirement R5 High VSL - As written it is unclear and ambiguous. As we understand the intent, this should say "notified less than all of the entities." The Severe VSL should say "did not notify any of the entities." Also after OR the Severe VSL should say "did not notify one or more entities in time..."
Response: Thank you for your comment. The CISDT has modified the VSL for R1 to better reflect the language in the requirement. The CISDT has also modified the Severe VSL to add the clarity you suggest.		
City of Austin dba Austin Energy	No	The VSLs for INT-006-4 go straight to severe in many cases. We request that the SDT consider a more graduated approach to the VSLs.
Response: Thank you for your comment. Certain requirements are assigned only a Severe VSL because those requirements are pass/fail. As the VSL Guidelines state, "If the required performance cannot be broken down to categorize degrees of noncompliant performance that at least partially meet the reliability objective of the requirement, any noncompliance with the requirement will have only one VSL – Severe."		
Colorado Spings Utilities	Yes	Thank you standard drafting team for all of your efforts. Please revise the VSL levels for this standard. The Violation Severity Levels are inappropriately high and disproportional to the risk to the Bulk Electric System.
Response: Thank you for your comment. VRFs, not VSLs, measure the risk to the Bulk Electric System. All of the requirements in INT-006-4 are assigned a Lower VRF, indicating that violating the requirements would not be expected to adversely affect the electrical state or capability of the Bulk Electric System. VSLs measure the degree of noncompliance, and the Severe VSLs simply indicate that the requirement is pass/fail. All pass/fail ("binary") VSLs must be assigned as Severe.		
Manitoba Hydro	Yes	(a) VSLs, R1, R2 - the words 'transition to Confirmed Interchange' do not reflect the language of the requirement and should be deleted (b) VSLs, R1 - there is no VSL related to the failure of the Balancing Authority to curtail a Confirmed Interchange

Organization	Yes or No	Question 22 Comment
		(c) VSLs, R5, High VSL vs. Severe VSL - it's currently difficult to decipher the difference between these two. Is the Severe VSL meant to be the failure to notify any of the entities?
Response: Thank you for your comment. The CISDT has deleted the words "transitioned to Confirmed Interchange" in the VSLs for R1 and R2 to better reflect the language in the requirement. The CISDT has also added language about curtailing a Confirmed Interchange to the R1 VSL. You are correct that the Severe VSL was intended to refer to the failure to notify any of the entities, and it has been modified to better indicate that.		
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
SPP Standards Review Group	Yes	
Duke Energy	Yes	
SERC OC Review Group	Yes	
ACES Standards Collaborators	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 22 Comment
MRO NERC Standards Review Forum	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
PJM Interconnection	Yes	

23. VRFs and VSLs for INT-009-2: The CISDT has proposed Violation Risk Factors and Violation Severity Levels for this standard. Do you agree with these compliance elements? If not, please provide specific substantive suggestions for improvements to the VRFs or VSLs.

Summary Consideration:

The SDT thanks all commenters who submitted feedback on the VRFs and VSLs. Per stakeholder comments, the SDT modified the VSLs for INT-004-3 R1, R2, and R3, INT-006-4 R1, R2, and R5, INT-009-2 R1, and INT-010-2 R1 and R2 to ensure that the VSL language is consistent with the language in the respective requirements. Some commenters questioned the Severe VSLs assigned to many requirements, and the SDT reminds these commenters that VRFs measure the impact to reliability of violating a specific requirement and VSLs measure the degree to which a standard was violated. A standard can have a Lower VRF, because violating it would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, and still have Severe VSL, indicating that the requirement is pass/fail. As the VSL Guidelines state, "If the required performance cannot be broken down to categorize degrees of noncompliant performance that at least partially meet the reliability objective of the requirement, any noncompliance with the requirement will have only one VSL – Severe."

Organization	Yes or No	Question 23 Comment
SPP Standards Review Group	No	We suggest deleting the phrase '...for that hour.' at the end of the Severe VSL for R1.
Response: Thank you for your comment. The CISDT agrees that deleting "…for that hour" makes the VSL consistent with the requirement language and has modified it accordingly. The CISDT has also added the phrase "at mutually agreed upon time intervals" after the first clause to reflect the time element to which the requirement refers.		
Florida Municipal Power Agency	No	INT-009 essentially describes inputs into the ACE equation, which are only Medium risk for 12 month rolling averages and 90% of clock ten minute periods during a month (BAL-001 R1 and R2) and Low (BAL-001 R3) VRFs; hence, each individual hourly input should be Low risk VRF. In addition, the BAL-001 standards adopt a non-zero defect approach (e.g., 90% of clock ten-minute interval during a month, 12 month rolling average) whereas the VSLs for INT-009 are zero-defect. This is

Organization	Yes or No	Question 23 Comment
		inconsistent treatment of an input to the ACE equation versus the ACE equation itself.
Response: Thank you for your comment. The requirements of INT-009 map directly from currently mandatory and enforceable standards INT-003-1 and INT-009-1. Each of those requirements is assigned a medium VRF. With regard to the VSLs, each requirement in INT-009-2 specifies performance which is binary in nature. For example, Requirement R3 states that the Balancing Authority shall coordinate operation of an HVDC tie for each Confirmed Interchange prior to its implementation. Either the Balancing Authority coordinated or they didn't. Similar conditions exist for R1 and R2. The CISDT does not believe that there is any way to gradate the VSLs and therefore must assign a binary VSL which is severe.		
ACES Standards Collaborators	No	(1) Because R1 and R2 are redundant with BAL-006 R4 and BAL-005 R12 and R12.3 respectively, we cannot support the VRFs for these requirements. The requirements should be struck. (2) If INT-009-2 R1 persists, the VRF should be classified as a Lower VRF. The requirement is redundant with BAL-006 R4 which has a Lower VRF. FERC guidelines for VRFs would require similar requirements to have the same VRFs and FERC has already approved the VRF for BAL-006 R4.
Response: Thank you for your comment. **1) BAL does not have an exclusion for Dynamic Schedules and does not have an inclusion for INT-010 R1-R3 and therefore the requirements are not redundant.** **2) Requirement R1 maps from the currently mandatory and enforceable INT-009-1, Requirement R1. This requirement has a medium VRF.**		
Colorado Spings Utilities	No	
Manitoba Hydro	Yes	(a) VSLs, R1 - the last words of this VSL is 'for that hour' but that concept doesn't appear in the requirement or standard. The requirement refers to 'mutually agreed upon time interval' and the VSL should reflect that.

Organization	Yes or No	Question 23 Comment
Response: Thank you for your comment. The CISDT agrees and has modified the VSL for R1 to delete "for that hour" and add "at mutually agreed upon time intervals" after the first clause to reflect the time element to which the requirement refers.		
Northeast Power Coordinating Council	Yes	
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
SERC OC Review Group	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	

Organization	Yes or No	Question 23 Comment
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
PJM Interconnection	Yes	

24. **VRFs and VSLs for INT-010-2: The CISDT has proposed Violation Risk Factors and Violation Severity Levels for this standard. Do you agree with these compliance elements? If not, please provide specific substantive suggestions for improvements to the VRFs or VSLs.**

Summary Consideration:

The SDT thanks all commenters who submitted feedback on the VRFs and VSLs. Per stakeholder comments, the SDT modified the VSLs for INT-004-3 R1, R2, and R3, INT-006-4 R1, R2, and R5, INT-009-2 R1, and INT-010-2 R1 and R2 to ensure that the VSL language is consistent with the language in the respective requirements. Some commenters questioned the Severe VSLs assigned to many requirements, and the SDT reminds these commenters that VRFs measure the impact to reliability of violating a specific requirement and VSLs measure the degree to which a standard was violated. A standard can have a Lower VRF, because violating it would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, and still have Severe VSL, indicating that the requirement is pass/fail. As the VSL Guidelines state, "If the required performance cannot be broken down to categorize degrees of noncompliant performance that at least partially meet the reliability objective of the requirement, any noncompliance with the requirement will have only one VSL – Severe."

Organization	Yes or No	Question 24 Comment
SPP Standards Review Group	No	We suggest changing the wording of the Severe VSL for R2 to:The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
Response: Thank you for your comment. The CISDT agrees that these slight changes add clarity and has made them.		
Colorado Spings Utilities	No	
Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 24 Comment
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	The VSL for INT-010-2 R4 states, "The Balancing Authority involved in a Pseudo-Tie or Dynamic Schedule failed to ensure that the MW value from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange was not exceeded in its ACE equation." The VSL does not include a duration of time. It is suggested that a period of time be included in the VSL.
Response: Thank you for your comment. The CISDT has deleted R4 based on stakeholder comments, so its accompanying compliance elements have been deleted as well.		
PacifiCorp	Yes	
Duke Energy	Yes	
SERC OC Review Group	Yes	
ACES Standards Collaborators	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Forum	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst Corporation	Yes	
MISO	Yes	

Organization	Yes or No	Question 24 Comment
MidAmerican Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
PJM Interconnection	Yes	

25. VRFs and VSLs for INT-011-1: The CISDT has proposed Violation Risk Factors and Violation Severity Levels for this standard. Do you agree with these compliance elements? If not, please provide specific substantive suggestions for improvements to the VRFs or VSLs.

Summary Consideration:

The SDT thanks all commenters who submitted feedback on the VRFs and VSLs. Per stakeholder comments, the SDT modified the VSLs for INT-004-3 R1, R2, and R3, INT-006-4 R1, R2, and R5, INT-009-2 R1, and INT-010-2 R1 and R2 to ensure that the VSL language is consistent with the language in the respective requirements. Some commenters questioned the Severe VSLs assigned to many requirements, and the SDT reminds these commenters that VRFs measure the impact to reliability of violating a specific requirement and VSLs measure the degree to which a standard was violated. A standard can have a Lower VRF, because violating it would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, and still have Severe VSL, indicating that the requirement is pass/fail. As the VSL Guidelines state, "If the required performance cannot be broken down to categorize degrees of noncompliant performance that at least partially meet the reliability objective of the requirement, any noncompliance with the requirement will have only one VSL – Severe."

Organization	Yes or No	Question 25 Comment
SERC OC Review Group	Yes	Yes. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Response: Thank you.		
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power	Yes	Yes, we agree with these compliance elements.

Organization	Yes or No	Question 25 Comment
Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
Response: Thank you for your support.		
SPP Standards Review Group	Yes	
Duke Energy	Yes	
PacifiCorp	Yes.	
Northeast Power Coordinating Council		Agree with the VRFs and VSLs.
ACES Standards Collaborators		Since the purpose of tagging intra-BA transactions is address commercial equity issues, we believe the requirement is a business practice and unnecessary for a reliability standard. Thus, we do not support the VRFs and VSLs.
Response: Thank you for your comment. As discussed throughout the comment report, in the rationale boxes in the standards, and elsewhere, the CISDT and a majority of other stakeholders believe that the standards are necessary for reliability.		

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed on (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).
8. Third draft of standard posted for 45 day formal comment period with parallel initial ballot (September 30 – November 15, 2013).

Description of Current Draft

This is the fourth draft of the proposed standard and is being posted for stakeholder comments and an additional ballot. This draft includes the modifications based on comments submitted by stakeholders.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	December 2013-January 2014
Recirculation ballot	January 2014
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become

effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Dynamic Transfers**
2. **Number:** INT-004-3
3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.
4. **Applicability:**

   4.1. Balancing Authority

   4.2. Purchasing-Selling Entity

5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of dynamic transfers.

   - R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement now includes Pseudo-Ties.
   - R2 is modified from INT-004-2 to separate the triggers for the review of the dynamic transfer and when a modification is required for the dynamic transfer.
   - R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo-Ties ensure that all entities involved are aware of the dynamic transfer and agree that the various responsibilities associated with the dynamic transfer have been agreed upon.
   - R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
   - The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any dynamic transfer.

B. Requirements and Measures

R1. Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning,*

Rationale for R1: This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

Same-day Operations]

M1. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-Tie. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the Purchasing-Selling Entity shall have evidence such as Interchange Distribution Calculator model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)

R2. The Purchasing-Selling Entity that submits a Request For Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

> Rationale for R2: This requirement does not preclude tags from being updated at any time. The requirement specifies conditions under which the tag must be updated.

2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.

2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.

2.3. The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

M2. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation met the criteria in Requirement R2, Parts 2.1- 2.3. (R2)

R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

> Rationale for R3: This Requirement is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. Transparency of all Pseudo-Ties ensures proper modeling by all impacted entities. This requirement will become effective when the NAESB Electric Industry Registry (EIR) accepts Pseudo-Tie registrations. Requirements for Pseudo-Tie registration will be defined in NAESB business practices which are developed through open industry practices. All existing Pseudo-Ties will need to be registered and verified. This will be addressed in the Project 2008-12 implementation plan.

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Purchasing-Selling Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Purchasing-Selling Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a Purchasing-Selling Entity or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method,
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.

R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority did not implement or operate a Pseudo-Tie that was included in the NAESB Electric Industry Registry publication.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-Ties are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as Scheduled Interchange. The obligations of the entities involved in each type of dynamic transfer are dependent on the type of dynamic transfer selected. These guidelines provide items that should be considered when determining which type of dynamic transfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a dynamic transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
    - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services FERC OATT Schedules 3–6 and other ancillary services as	Attaining BA	Native BA

required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE Frequency Bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their Frequency Bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BA(s) by the Pseudo-Tie	The Attaining BA should include the Load from its dynamic schedule as a part of its forecast load to set frequency bias requirement. The Native BA should change its Load used to set Frequency Bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

In NERC's Dynamic Transfer Reference Guidelines, Version 2, it describes unique handling of curtailments of dynamic transfers.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as dynamic transfer signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe that when Curtailments (typically communicated through e-Tags) of dynamic transfers occur, they require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed on (February 12, 2009).
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7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

~~7.~~8. Third draft of standard posted for 45 day formal comment period with parallel initial ballot (September 30 – November 15~~3~~, 2013).

Description of Current Draft

This is the fourth ~~third~~ draft of the proposed standard and is being posted for stakeholder comments and an additional ~~initial~~ ballot. This draft includes the modifications based on comments submitted by stakeholders~~, as well as items identified in the SAR and applicable FERC directives from FERC Order 693~~.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	December 2013-January 2014~~September – October 2013~~
Recirculation ballot	January~~December~~ 2014~~3~~
BOT adoption	February~~January~~ 2014
File standard with regulatory authorities.	February 2014

Effective Dates

First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Dynamic Transfers**

2. **Number:** INT-004-3

3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. ~~Load-Serving~~Purchasing-Selling Entity

5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of dynamic transfers.

   - R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement ~~replaces the Purchasing Selling Entity with the Load Serving Entity and~~now includes Pseudo-Ties~~ were added~~.
   - R2 is modified from INT-004-2 to separate the triggers for the review of the dynamic transfer and when a modification is required for the dynamic transfer.
   - R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo-~~-~~Ties ensure that all entities involved are aware of the dynamic transfer and agree that ~~that~~ the various responsibilities associated with the dynamic transfer have been agreed upon.
   - R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
   - The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any dynamic transfer.

B. Requirements and Measures

R1. Each ~~Load-Serving~~ Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*]

> Rationale for R1: This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

[*Time Horizon: Operations Planning, Same-day Operations*]

M1. The ~~Load-Serving~~Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-Tie. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the ~~Load-Serving~~Purchasing-Selling Entity shall have evidence such as Interchange Distribution Calculator model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)

R2. The ~~Each Load-Serving~~Purchasing-Selling Entity that submits a Request For Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

> Rationale for R2: This requirement does not preclude tags from being updated at any time. The requirement specifies conditions under which the tag must be updated.

2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.

2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.

2.3. ~~-~~The ~~Load-Serving~~Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

M2. The ~~Load-Serving~~Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation met the criteria in Requirement R2, Parts 2.1- 2.3. (R2)

R3. Each ~~Attaining~~ Balancing Authority shall only implement or operate a ~~register each~~ Pseudo-Tie ~~for which data is used in its ACE equation~~ that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures. [*Violation Risk*

> Rationale for R3: This Requirement is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. Transparency of all Pseudo-Ties ensures proper modeling by all impacted entities. This requirement will become effective when the NAESB Electric Industry Registry (EIR) accepts Pseudo-Tie registrations. Requirements for Pseudo-Tie registration will be defined in NAESB business practices which are developed through open industry practices. All existing Pseudo-Ties will need to be registered and verified. This will be addressed in the Project 2008-12 implementation plan.

Factor: Lower] [*Time Horizon: Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated ~~registered~~ a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication ~~prior to its implementation~~. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The ~~Load-Serving~~Purchasing-Selling Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The ~~Load-Serving~~Purchasing-Selling Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a ~~Load-Serving~~Purchasing-Selling Entity or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The ~~Load-Serving~~Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method,
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3 and was expected to persist, but the ~~Load-Serving~~Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated

						for future hours.
R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority did not ~~register~~ implement or operate a Pseudo-Tie ~~for which data was used in its ACE equation~~ that was included in the NAESB Electric Industry Registry publication.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-T~~t~~ies are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as ~~s~~Scheduled ~~i~~Interchange. The obligations of the entities involved in each type of dynamic transfer are dependent on the type of dynamic transfer selected. These guidelines provide items that should be considered when determining which type of dynamic transfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a dynamic transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
  - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services FERC OATT Schedules 3–6 and other ancillary services as	Attaining BA	Native BA

required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE F~~f~~requency ~~b~~Bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their F~~f~~requency B~~b~~ias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BA(s) by the ~~p~~Pseudo-~~t~~Tie	The Attaining BA should include the ~~l~~Load from its dynamic schedule as a part of its forecast load to set frequency bias requirement. The Native BA should change its ~~l~~Load used to set ~~f~~Frequency ~~b~~Bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

In NERC's Dynamic Transfer Reference Guidelines, Version 2, it describes unique handling of curtailments of dynamic transfers.

For Dynamic Schedules:

> **If transmission service between the ~~s~~Source and ~~s~~Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including ~~d~~Dynamic ~~s~~Schedules, may have to be curtailed accordingly. All BAs involved in a ~~d~~Dynamic ~~s~~Schedule curtailment must also adjust the ~~d~~Dynamic ~~s~~Schedule signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed D~~d~~ynamic ~~s~~Schedule tag. Since ~~d~~Dynamic ~~s~~Schedule tags are generally not used as dynamic transfer signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-T~~t~~ies:

> **If transmission service between the ~~n~~Native and ~~a~~Attaining BA(s) is curtailed, then the allowable range of the magnitude of the ~~p~~Pseudo-~~t~~Ties between them must be limited accordingly to these constraints.**

Both sections above describe that when ~~c~~Curtailments (typically communicated through e-Tags) of dynamic transfers occur, they require additional action by Balancing Authorities to ensure compliance with the C~~c~~urtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including C~~c~~urtailments, in Dynamic Schedule and Pseudo-T~~t~~ie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
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4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).
8. Third draft of standard posted for 45 day formal comment period with parallel initial ballot (September 30 – November 15, 2013).

Description of Current Draft

This is the fourth draft of the proposed standard and is being posted for stakeholder comments and an additional ballot. This draft includes the modifications based on comments submitted by stakeholders.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Additional Ballot	December 2013 – January 2014
Recirculation ballot	January 2014
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD		New

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Interchange Initiation and Modification for Reliability**
2. **Number: INT-010-2**
3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.
4. **Applicability:**

   4.1. Balancing Authority

5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to replace "request for Arranged Interchange" with the correct term "Request for Interchange". A rationale was developed to clarify use of the term "energy sharing agreement" for this requirement.
   - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.

B. Requirements and Measures

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

> Rationale for R1: This requirement was originally revised to replace the term "Request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted an RFI per Requirement R1. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was submitted within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a RFI was submitted reflecting that Interchange schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, and R3, for the most recent three calendar months plus the current month.
- If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a RFI was submitted following the resource loss.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a RFI was submitted within 60 minutes following the start of the scheduled Interchange.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).
8. ~~7.~~Third draft of standard posted for 45 day formal comment period with parallel initial ballot (September 30 – November 15~~3~~, 2013).

Description of Current Draft

This is the ~~third~~ fourth draft of the proposed standard and is being posted for stakeholder comments and an ~~initial~~ additional ballot. This draft includes the modifications based on comments submitted by stakeholders~~, as well as items identified in the SAR and applicable FERC directives from FERC Order 693~~.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Additional ~~Initial~~ Ballot	December ~~September – October~~ 2013 – January 2014
Recirculation ballot	January 2014~~December 2013~~
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD		New

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Interchange Initiation and Modification for Reliability**
2. **Number:** **INT-010-2**
3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.
4. **Applicability:**

   4.1. Balancing Authority

   ~~**4.2.**~~

5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to replace "request for Arranged Interchange" with the correct term "Request for Interchange". A rationale was developed to clarify use of the term "energy sharing agreement" for this requirement.
   - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.
   - ~~R4 was created to address the fact that when a Reliability Adjustment Arranged Interchange is approved for a Pseudo-Tie or Dynamic Schedule, the Native and Attaining Balancing Authorities must take action to meet MW relief obligations resulting from an implemented Reliability Adjustment Arranged. action is required by the Balancing Authority to ensure that the data source feeding the Net Interchange value of ACE value does not exceed the MW value of the Reliability Adjustment Arranged Interchange.~~

B. Requirements and Measures

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [*Violation*

Rationale for R1: This requirement was originally revised to replace the term "Request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

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Risk Factor: Lower] [*Time Horizon: Real Time Operations*]

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted an RFI per Requirement R1. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting ~~that~~ a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was ~~created~~ submitted within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a RFI was ~~created~~ submitted reflecting that Interchange schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

~~**R4.** Each Balancing Authorityinvolved in a Pseudo-Tie or Dynamic Schedule shall ensure the MW value from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange is not exceeded in their ACE equation. [*Violation Risk Factor: Medium*] [*Time Horizon: Real Time Operations*]~~

~~**M4.** The Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that,~~

~~Rationale for R1: The Balancing Authority is responsible for implementing the Confirmed Interchange that results from a Reliability Adjustment Arranged Interchange. Future actions may be taken by the Balancing Authority or other entities that may reduce or eliminate the curtailment.~~

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~~following any Reliability Adjustment Arranged Interchange on a Pseudo-Tie or Dynamic Schedule, it ensured the MW value from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange was not exceeded in their ACE equation. (R4)~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, and R3, ~~and R4~~ for the most recent three calendar months plus the current month.
- If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a RFI was submitted following the resource loss.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting ~~the~~ a modification was submitted within 60 minutes following the start of ~~the~~ that modification.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a RFI was submitted within 60 minutes following the start of the scheduled Interchange.
~~**R4**~~	~~Real Time Operations~~	~~Lower~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority involved in a Pseudo-Tie or Dynamic Schedule failed to ensure that the MW value from the Confirmed Interchange resulting from a Reliability Adjustment Arranged Interchange was not exceeded in its ACE equation.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

In NERC's Dynamic Transfer Reference Guidelines, Version 2, it describes unique handling of ~~c~~Curtailments of dynamic transfers.

For Dynamic Schedules:

> **If transmission service between the S~~s~~ource and ~~s~~Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule ~~c~~Curtailment must also adjust the Dynamic Schedule signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as dynamic transfer signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-~~t~~Ties:

> **If transmission service between the ~~n~~Native and ~~a~~Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe that when ~~c~~Curtailments (typically communicated through e-Tags) of dynamic transfers occur, they require additional action by Balancing Authorities to ensure compliance with the C~~c~~urtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including ~~c~~Curtailments, in Dynamic Schedule and Pseudo-~~t~~Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the dynamic transfer signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the dynamic transfer signal in order to comply with the ~~c~~Curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Proposed Definitions for the NERC Glossary of Terms

Project 2008-12: Coordinate Interchange Standards

The Coordinate Interchange Standards Drafting (CISDT) received comments on the proposed set of definitions to be revised or added to the NERC Glossary of Terms. The CISDT made substantive revisions to two of the definitions based on these comments. These revised definitions are streamlined and are an improvement to the previously proposed definitions. These two defined terms are being posted for a 45-day comment period with ballot being conducted over the last 10 days of the comment period.

Revisions to Defined Terms in the NERC Glossary

- **Request for Interchange** - A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.

- **Arranged Interchange** - The state where a Request for Interchange (initial or revised) has been submitted for approval.

Proposed Definitions for the NERC Glossary of Terms

Project 2008-12: Coordinate Interchange Standards

The Coordinate Interchange Standards Drafting (CISDT) received comments on the proposed set of definitions to be revised or added to the NERC Glossary of Terms. The CISDT made substantive revisions to two of the definitions based on these comments. These revised definitions are streamlined and are an improvement to the previously proposed definitions. These two defined terms are being posted for a 45-day comment period with ballot being conducted over the last 10 days of the comment period.

Revisions to Defined Terms in the NERC Glossary

- **Request for Interchange** - A collection of data as defined in the NAESB Business Practice Standards~~, to be~~ submitted ~~to the Sink Balancing Authority~~ for the purpose of implementing bilateral Interchange between ~~a Source and Sink~~ Balancing Authorities~~y~~ or an energy transfer within a single Balancing Authority.

- **Arranged Interchange** - The state where a Request for Interchange ~~the Sink Balancing Authority~~ (initial or revised) has been submitted for approval. ~~has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).~~

Implementation Plan

Project 2008-12: Coordinate Interchange Standards

Requested Approvals

- INT-004-3 — Dynamic Transfers
- INT-006-4 — Evaluation of Interchange Transactions
- INT-009-2 — Implementation of Interchange
- INT-010-2 — Interchange Initiation and Modification for Reliability
- INT-011-1 — Intra-Balancing Authority Transaction Identification

Requested Retirements

- INT-001-3 Interchange Information
- INT-003-3 Interchange Transaction Implementation
- INT-004-2 Dynamic Interchange Transaction Modifications
- INT-005-3 Interchange Authority Distributes Arranged Interchange
- INT-006-3 Response to Interchange Authority
- INT-007-1 Interchange Confirmation
- INT-008-3 Interchange Authority Distributes Status
- INT-009-1 Implementation of Interchange
- INT-010-1 Interchange Coordination Exemptions

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

- **Dynamic Interchange Schedule or Dynamic Schedule:** A time-varying energy transfer that is updated in Real-time and included in the Net Interchange Schedule term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Pseudo-Tie:** A time-varying energy transfer that is updated in Real-time and included in the Net Interchange Actual term (NI_A) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

- **Request for Interchange** - A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.
- **Arranged Interchange** - The state where a Request for Interchange (initial or revised) has been submitted for approval.
- **Confirmed Interchange** - The state where no party has denied and all required parties have approved the Arranged Interchange.
- **Adjacent Balancing Authority** - A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
- **Intermediate Balancing Authority** - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
- **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.
- **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.
- **Operational Planning Analysis:** An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Proposed additional Defined Terms to be added to the NERC Glossary

- **Reliability Adjustment Arranged Interchange** – A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
- **Composite Confirmed Interchange –** The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
- **Attaining Balancing Authority:** A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.
- **Native Balancing Area:** A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

Background

The standards were developed under Project 2008-12, Coordinate Interchange Standards. The drafting team revised the existing approved standards and grouped the requirements in distinct groupings within each standard. The drafting team developed a new standard, INT-011-1, Intra-Balancing Authority Transaction Identification, in response to a FERC directive in Order 693, paragraph 817:

> *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

The proposed revision to the definition of Operational Planning Analysis addresses a FERC Order 693 directive:

> *866. Accordingly, the Commission approves Reliability Standard INT-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.*

The Reliability Coordinator and Transmission Operator are required to perform an Operational Planning Analysis in existing IRO-008-1, Requirement R1 and in TOP-002-3, Requirement R1 which was filed with FERC on April 16, 2013. By including the term "Interchange" explicitly in the definition, the drafting team has addressed the directive.

Applicable Entities

- Balancing Authority
- Transmission Service Provider
- Load-Serving Entities

Effective Date

First day of the second calendar quarter beyond the date each standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date each standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

Midnight of the day immediately prior to the Effective Date of the new standards in the particular jurisdiction in which the new standards are becoming effective.

Implementation Plan for Definitions

Entities shall use all proposed definitions when implementing any requirements within the new standards which use the defined term(s).

Implementation Plan for INT-004-3, Requirement R3

Requirement R3 is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. A request to revise the NAESB Electric Industry Registry has already been submitted for implementation. This requirement will become effective on the first calendar day two calendar quarters after the NAESB Electric Industry Registry is able to accept Pseudo-Tie registrations. All existing and future Pseudo-Ties are to be registered in the NAESB Electric Industry Registry.

Implementation Plan

Project 2008-12: Coordinate Interchange Standards

Requested Approvals

- INT-004-3 — Dynamic Transfers
- INT-006-4 — Evaluation of Interchange Transactions
- INT-009-2 — Implementation of Interchange
- INT-010-2 — Interchange Initiation and Modification for Reliability
- INT-011-1 — Intra-Balancing Authority Transaction Identification

Requested Retirements

- INT-001-3 Interchange Information
- INT-003-3 Interchange Transaction Implementation
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- INT-005-3 Interchange Authority Distributes Arranged Interchange
- INT-006-3 Response to Interchange Authority
- INT-007-1 Interchange Confirmation
- INT-008-3 Interchange Authority Distributes Status
- INT-009-1 Implementation of Interchange
- INT-010-1 Interchange Coordination Exemptions

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

- **Dynamic Interchange Schedule or Dynamic Schedule:** A time-varying energy transfer that is updated in R~~r~~eal-time and included in the Net Interchange Schedule~~d~~ term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Pseudo-Tie:** A time-varying energy transfer that is updated in R~~r~~eal-~~-~~time and included in the Net Interchange Actual term (NI_A) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

- **Request for Interchange** - A collection of data as defined in the NAESB Business Practice Standards~~, to be~~ submitted ~~to the Sink Balancing Authority~~ for the purpose of implementing bilateral Interchange between ~~a Source and Sink~~ Balancing Authorit<u>ies</u>~~y~~ or <u>an energy transfer</u> within a single Balancing Authority.
- **Arranged Interchange** - The state where <u>a Request for Interchange</u> ~~the Sink Balancing Authority~~ <u>(initial or revised) has been submitted for approval.</u> ~~has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).~~
- **Confirmed Interchange** - The state where no party has denied and all required parties have approved the Arranged Interchange.
- **Adjacent Balancing Authority** - A Balancing Authority whose Balancing Authority Area ~~that~~ is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
- **Intermediate Balancing Authority** - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
- **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and <u>any</u>~~the~~ resulting Interchange Schedule.
- **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for ~~the~~ <u>any</u> resulting Interchange Schedule.
- **Operational Planning Analysis:** An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Proposed additional Defined Terms to be added to the NERC Glossary

- **Reliability Adjustment Arranged Interchange** ~~-~~<u>–</u> <u>A</u> ~~R~~<u>r</u>equest to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
- **Composite Confirmed Interchange –** The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
- **Attaining Balancing Authority:** A Balancing Authority bringing generation or load into its effective control boundaries through a ~~d~~<u>D</u>ynamic ~~t~~<u>T</u>ransfer from the Native Balancing Authority.
- **Native Balancing Area:** A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a <u>D</u>~~d~~ynamic ~~t~~<u>T</u>ransfer.

Background

The standards were developed under Project 2008-12, Coordinate Interchange Standards. The drafting team revised the existing approved standards and grouped the requirements in distinct groupings within each standard. The drafting team developed a new standard, INT-011-1, Intra-Balancing Authority Transaction Identification, in response to a FERC directive in Order 693, paragraph 817:

> *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

The proposed revision to the definition of Operational Planning Analysis addresses a FERC Order 693 directive:

> *866. Accordingly, the Commission approves Reliability Standard INT-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.*

The Reliability Coordinator and Transmission Operator are required to perform an Operational Planning Analysis in existing IRO-008-1, Requirement R1 and in TOP-002-3, Requirement R1 which was filed with FERC on April 16, 2013. By including the term "Interchange" explicitly in the definition, the drafting team has addressed the directive.

Applicable Entities

- Balancing Authority
- Transmission Service Provider
- Load-Serving Entities

Effective Date

First day of the second calendar quarter beyond the date each standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date each standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

Midnight of the day immediately prior to the Effective Date of the new standards in the particular jurisdiction in which the new standards are becoming effective.

Implementation Plan for Definitions

Entities shall use all proposed definitions when implementing any requirements within the new standards which use the defined term(s).

Implementation Plan for INT-004-3, Requirement R3

Requirement R3 is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. A request to revise the NAESB Electric Industry Registry has already been submitted for implementation. This requirement will become effective on the first calendar day two calendar quarters after the NAESB Electric Industry Registry is able to accept Pseudo-Tie registrations. All existing and future Pseudo-Ties are to be registered in the NAESB Electric Industry Registry.

Unofficial Comment Form

Project 2008-12 Coordinate Interchange Standards

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft INT-004-3 and INT-010-2 standards. The electronic comment form must be completed by 8:00 p.m. Eastern on **January 22, 2013**.

If you have questions please contact Steve Crutchfield via email or by telephone at 609-651-9455.

The project page may be accessed by clicking here.

Background Information

The Coordinate Interchange Standard Drafting Team (CISDT) posted drafts of INT-004-3—Dyanmic Transfers, INT-006-4—Evaluation of Interchange Transactions, INT-009-2—Implementation of Interchange, INT-010-2—Interchange Initiation and Modification for Reliability, and INT-011-1—Intra-Balancing Authority Transaction Identification, along with nine revised definitions and four new definitions, for a 45-day comment and ballot period from September 30-November 15, 2013. Support for the standards and definitions was generally high. The CISDT considered each of the comments submitted and has incorporated those that the team found to improve the quality of the standards.

INT-006-4, INT-009-2, INT-011-2, and most of the definitions (Pseudo-Tie, Adjacent Balancing Authority, Confirmed Interchange, Intermediate Balancing Authority, Sink Balancing Authority, Source Balancing Authority, Dynamic Schedule, Reliability Adjustment Arranged Interchange, Composite Confirmed Interchange, Attaining Balancing Authority, Native Balancing Area) earned stakeholder approval of 68% or more in the ballot, and the CISDT did not make any substantive changes to these standards or definitions based on stakeholder comments. Those standards and definitions will proceed to final ballot.

INT-004-3 received 67.35% approval in the ballot, but the CISDT was persuaded by stakeholder comments to make the following improvements to the standard:

- Changed the definitions of Request for Interchange (RFI) and Arranged Interchange to enhance clarity. (While the revised definitions of Arranged Interchange and Request for Interchange received 77.82% approval as part of the package of all definitions, the CISDT was persuaded by stakeholder comments to make improvements to the definitions to add clarity.
- Changed Load-Serving Entity to Purchasing-Selling Entity in the Applicability and Compliance sections and in R1 and R2 in response to industry comments.
- Made changes to the Background section to reflect changes to the standards.
- Added language in the R1 Rationale section to clarify that if no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

- Added language in the R2 Rationale section to clarify that R2 does not preclude tags from being updated at any time, and that the requirement specifies conditions under which the tag must be updated.
- Made changes to R3 to clarify Balancing Authority obligations with respect to Pseudo-Ties included in the NAESB Electric Industry Registry publication.
- Modified the VSLs for R1, R2, and R3 to ensure that the language is consistent with the language in the requirements.
- Made minor changes to the definition of Sink Balancing Authority, Attaining Balancing Authority, Native Balancing Authority, and to the Background section and the R3 Rationale box for consistency or to correct typographical errors.
- Made various errata changes to ensure that capitalization of glossary terms and acronym usage is consistent across the standard.

INT-010-2 received 58.03% approval in the ballot, and the CISDT made the following improvements to address stakeholder comments:

- Added language and a Rationale box to R1 to provide clarity around “energy sharing agreement.”
- Deleted R4 in response to industry comments that R4 is primarily commercial equity-driven and provides only a marginal, if any, reliability benefit.
- Made minor changes to the Applicability Section, R1, R2, M2, and M3 for consistency or to correct typos.
- Modified the VSLs in R1 and R2 to ensure that the language is consistent with the language in the requirement.
- Made various errata changes to ensure that capitalization of glossary terms and acronym usage is consistent across the standard.

The revised two standards and two definitions are posted for a 45-day comment and ballot period from December 9, 2013-January 22, 2014, with a 10-day ballot period from January 10-22, 2014. **Note that all definitions have been stripped from the individual standards in favor of posting separate definition documents.**

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Question

1. The drafting team has revised INT-004-3 in response to stakeholder comments. Do you support the proposed changes?

☐ Yes
☐ No

Comments:

2. The drafting team has the definition of Request for Interchange (RFI) in response to stakeholder comments. Do you support the proposed changes?

☐ Yes
☐ No

Comments:

3. The drafting team has revised the definition of Arranged Interchange in response to stakeholder comments. Do you support the proposed changes?

☐ Yes
☐ No

Comments:

4. The drafting team has revised INT-010-2 in response to stakeholder comments. Do you support the proposed changes?

☐ Yes
☐ No

Comments:

Project 2008-12 - Coordinate Interchange Standards

Mapping Document

Project Purpose

The purpose of Project 2008-12 is to revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange. The drafting team also addressed the Interchange Subcommittee concerns related to the dynamic Transfers and Pseudo-ties and addressed previously identified stakeholder comments and applicable directives from Order 693. These issues and directives include defining communications on reloading interchange transactions due to different operational conditions and to bringing the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for: **R1.1.** All Dynamic Schedules at the expected average MW profile for each hour. Independent Expert Review recommendation: Retain Requirement.	Revised and Moved into INT-004-3	**INT-004-3:** **R1.** Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*] CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.
R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority: **R2.1.** If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator. **R2.2.** For each bilateral Inadvertent Interchange payback. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Retired	The CI SDT believes that this requirement is no longer necessary for reliability. Since the proposed INT-009-2 R1 makes it clear that the Net Scheduled Interchange term in the control equation can only include Confirmed Interchange as agreed to between Balancing Authorities, this by definition requires that an Arranged Interchange be created in order to implement the schedules listed in R2.1 and R2.2. From a reliability perspective, it is unimportant who creates these Arranged interchanges – only that they be created and confirmed prior to being entered into the control equation. CISDT Consideration of Independent Expert Review

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		recommendation: The CISDT concurs.

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. **R1.1.** The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including: **R1.1.1.** Interchange Schedule start and end time. **R1.1.2.** Energy profile. **R1.2.** If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing	Revised and Moved into INT-009-2	**INT-009-2:** R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign or direction to that of the

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie. Independent Expert Review recommendation: Retain Requirement.		Adjacent Balancing Authority. R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual (NI_A) term of their respective control ACE (or alternate control process). [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] R3. Each Balancing Authority in whose area the HVDC tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie. [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations, Operations Planning] CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Retired	The CI SDT believes that at a minimum, this requirement does not belong in the "Dynamic Schedules" standard. However, for several reasons, the CI SDT further believes that this specific requirement is no longer required: • It mandates a practice (releasing of E-Tag limits) that is process related. • The practice is already addressed in related NAESB standards (WEQ-004 Appendix B - E-Tag Actions). • Use of a limit (and the associated release of that limit) is only one particular way to address curtailments. Other ways exist that could be used in lieu of this approach. The reliability standard should not mandate a single approach when others may suffice. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.
R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the	Revised	**INT-004-2** **R2.** The Purchasing-Selling Entity that submitted a

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
tag is updated for the next available scheduling hour and future hours when any one of the following occurs: **R2.1.** The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +10%. **R2.2.** The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +25 megawatt-hours. **R2.3.** A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		Request For Interchange in accordance with Requirement R1, shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same Day Operations, Real Time Operations] 2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist. 2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist. 2.3. The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have the RFI updated for a Dynamic Schedule or Pseudo-Tie that is significantly different than the original schedule. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis.

Standard: INT-005-3, Interchange Authority Distributes Arranged Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange. **R1.1.** When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Retired	The CISDT is proposing retirement of this requirement. The entities to receive the transaction are included today in the eTag specification, Section 3.6.1.1.1. The timing requirement for the distribution of tags is removed from this standard, as they are currently included and expected to remain in the NAESB documentation. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange. **R1.1.** Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to: **R1.1.1.** Energy profile (ability to support the magnitude of the Interchange). **R1.1.2.** Ramp (ability of generation maneuverability to accommodate). **R1.1.3.** Scheduling path (proper connectivity of Adjacent Balancing Authorities). **R1.2.** Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the	Revised	R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange. 1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid. R2. Each Transmission Service Provider shall approve

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid. CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that this distribution requirement may currently drive how software performs this function. However, if that software were not present, this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		interchange to occur.

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following: **R1.1.** Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate). **R1.2.** All reliability entities involved in the Arranged Interchange are currently in the NERC registry. **R1.3.** The following are defined: **R1.3.1.** Generation source and load sink. **R1.3.2.** Megawatt profile. **R1.3.3.** Ramp start and stop times. **R1.3.4.** Interchange duration. **R1.4.** Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.	Retired, Revisions made to defined term used in various INT standards to clarify reliability objective	R1.1, R1.2 and R1.3 ensure the data submitted on the interchange is valid. This activity occurs in software validation and is not appropriate for a reliability standard; these items are included in the Technical Basis and Guidelines section of INT-006. Interchange that does not meet these criteria would not be an Arranged Interchange. R1.4. is addressed in the proposed revision to the definition of Confirmed Interchange: *The state where no party has denied and all required parties have approved the Arranged Interchange.* INT-006-4, Requirement R4 also specifies conditions under which the BA shall not transition to Confirmed Interchange: R4. Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: [Violation Risk Factor: Lower] [Time

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		Horizon: Operations Planning, Same-day Operations, Real-time Operations] • It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition. • It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition. • It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-008-3, Interchange Authority Distributes Status		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange. **R1.1.** For Confirmed Interchange, the Interchange Authority shall also communicate: **R1.1.1.** Start and stop times, ramps, and megawatt profile to Balancing Authorities. **R1.1.2.** Necessary Interchange information to NERC-identified reliability analysis services. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised and moved into INT-006-4	**INT-006-4:** R5. Each Sink Balancing Authority shall distribute all notifications of whether an Arranged Interchange was transitioned to Confirmed Interchange to the following entities, and notifications of on-time Confirmed Interchange shall be distributed such that they are delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 5.1. The Source Balancing Authority, 5.2. Each Intermediate Balancing Authority, 5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange, 5.4. Each Transmission Service Provider included in the Arranged Interchange, and 5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

Standard: INT-008-3, Interchange Authority Distributes Status		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that this distribution requirement may currently drive how software performs this function. However, if that software were not present, this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the interchange to occur.

Standard: INT-009-1, Implementation of Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Combined with INT-003-3, Requirement R1	**INT-009-2** **R1.** Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs that a separate requirement is not necessary. This requirement was combined with INT-003-3, Requirement R1.

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised	**INT-010-2:** **R1.** The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		data for reliability analysis
R2. For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised	**INT-010-2:** **R2.** Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R3. For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised	**INT-010-2:** **R3.** Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard	Modifications to Coordinate Interchange Standards for Applicability and General Upgrade
Request Date	May 27, 2008
Modified Date	December 1, 2008

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Interchange Subcommittee	☐	New Standard
Primary Contact Don Lacen, IS Chair	☒	Revision to existing Standards INT-001-2 — Interchange Transaction Tagging INT-003-2 — Interchange Transaction Implementation INT-004-1 — Interchange Transaction Modifications INT-005-2 — Interchange Authority Distributes Arranged Interchange INT-006-2 — Response to Interchange Authority INT-007-1 — Interchange Confirmation INT-008-2 — Interchange Authority Distributes Status INT-009-1 — Implementation of Interchange INT-010-1 — Interchange Coordination Exemptions
Telephone 505-241-2032 Fax 505-241-2582	☐	Withdrawal of existing Standard
E-maildon.lacen@pnm.com	☐	Urgent Action

Purpose **(Describe the proposed standard action: Nomination of a proposed standard, revision to a standard, or withdrawal of a standard and describe what the standard action will achieve.)** Revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange; to address the Interchange Subcommittee concerns related to the Dynamic Transfers and Pseudo-ties; to address previously identified stakeholder comments

and applicable directives from Order 693; to define communications on reloading interchange transactions due to different operational conditions; and to bring the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

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.)

There is confusion regarding the Interchange Authority "function". The need for improved clarity became apparent when entities were recently asked to register in the Compliance Registry as "Interchange Authorities" and entities had difficulty determining which entities were performing the Interchange Authority tasks identified in the set of Coordinate Interchange standards. The Interchange Authority activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities.

The Coordinate Interchange standards dealing with the Interchange Authority and the current Functional Model representations of the Interchange Authority do not reflect technological advances made since the Functional Model working group originally defined the Interchange authority and advances made since the Coordinate Interchange standards were written.

There are different interpretations surrounding the requirements associated with Dynamic Transfers and Pseudo-ties. Adding definitions for the terms used to reference Dynamic Transfers and Pseudo-ties (e.g., Dynamic Schedule, Dynamic Transfer, Pseudo-tie, Dynamic Schedule Curtailment) will add clarity to these requirements.

Additional requirements may be needed to address the principles outlined in the Interchange Subcommittee's Principles and Definitions Supporting Dynamic Transfers and Pseudo-ties. (Attachment 2)

Review the current NERC Glossary of Terms related to interchange to determine if any revisions or new definitions are necessary as a result of the Interchange standards development.

The work in this project should be addressed in at least two phases with a ballot conducted at the end of each phase. The first phase is needed as soon as possible and should focus on the revisions needed to ensure that each requirement is assigned to a user, owner or operator of the bulk power system. All other proposed revisions should be addressed in the second or subsequent phase(s) of the project.

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

The modifications in the set of Coordinate Interchange Standards should address the following:

- Determine if the activities in the Coordinate Interchange standards correctly identify the responsible entity.
- Consider requiring each Sink Balancing Authority or its designee to be responsible for providing the Interchange Authority functions using an interchange transaction tool process as defined in the latest approved version of the e-Tag

Specifications.

- The existing requirements are tool-neutral. Consider adding specific references to the e-Tagging process, applications, and tools in the requirements
- Consider adding a requirement to have backup capability for use when the interchange transaction tool fails.
- Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to follow.
- Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factor drafting team. (See Attachment 1)
- Determine if there is industry-wide support for the Interchange Subcommittee's Principles and definition supporting dynamic transfers and pseudo-ties, and if there is support, modify the requirements and add definitions accordingly.
- If there are no tasks assigned to the Interchange Authority function, then make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity.

Make other changes to the standards to bring them into conformance with the latest version of the Reliability Standards Development Procedure, Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

The work in this project should be done in two or more phases, with the first phase focused solely on clarifying the applicability of each requirement in the existing set of standards. All other revisions should take place in a second or subsequent phase(s).

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Revise the following set of Coordinate Interchange Standards so that the responsibility for each of the requirements is clearly assigned to an owner, operator or user of the bulk power system, and not to a tool.

INT-001-2 — Interchange Transaction Tagging

INT-003-2 — Interchange Transaction Implementation

INT-004-1 — Interchange Transaction Modifications

INT-005-2 — Interchange Authority Distributes Arranged Interchange

INT-006-2 — Response to Interchange Authority

INT-007-1 — Interchange Confirmation

INT-008-2 — Interchange Authority Distributes Status

INT-009-1 — Implementation of Interchange

INT-010-1 — Interchange Coordination Exemptions

Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to follow.

Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factor drafting team. (See Attachment 1)

Address the principles and definitions proposed by the Interchange Subcommittee in support of dynamic transfers and pseudo-ties. (See Attachment 2)

Make other changes to the standards to bring them into conformance with the latest version of the Reliability Standards Development Procedure, Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

If there are no tasks assigned to the Interchange Authority function, then make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity.
The work in this project should be addressed in at least two phases with a ballot conducted at the end of each phase. The first phase is needed as soon as possible and should focus on the revisions needed to ensure that each requirement is assigned to a user, owner or operator of the bulk power system. All other proposed revisions should be addressed in the second or later phases of the project.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	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 a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	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.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	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
CIP-002-1 through CIP-009-1	If the industry determines that the IA Function is not an "owner, operator or user" of the BES, then the applicability section of these standards should be modified to remove the IA as a responsible entity.

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1

(Issues originally intended for Project 2009-03 – Interchange Information)

INT-001-2 Interchange Information

Directives from FERC Order 693

- Include a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.
- Consider Santa Clara's comments about the applicability of the LSE in the standard as part of the standards development process.

V0 Industry Comments

- R1 - Too stringent
- R1 – Who tags dynamic schedules?
- Load PSE responsibility is new restriction
- Clarify tagging of reserves
- R2.2 – 60 minute time frame questioned
- Question on generation scheduling
- Onerous to BA's
- More commercial problem than reliability
- Lack of compliance

VRF Comments

- R1, 1.1, 2, 2.1, 2.2 – commercial and administrative

INT-003-2 Interchange Transaction Implementation

Unresolved Directives from FERC Order 693 – none

VRF Comments

- R1, 1.1, 1.1.2, 1.2 – commercial and administrative

INT-004-1 Dynamic Interchange Transaction Modifications

Unresolved Directives from FERC Order 693 – none

V0 Industry Comments

- Replace TSP with TOP
- Need to address tag curtailment
- Suggested non-compliance levels
- Non-compliance based on %
- Use WECC criteria

VRF Comments

- R2, 2.2, 2.3 – commercial and administrative

INT-005-2 Interchange Authority Distributes Arranged Interchange

Unresolved Directives from FERC Order 693 – none

VRF Comment

– R5 – administrative

INT-006-2 Response to Interchange Authority

Directives from FERC Order 693

– Include reliability coordinators and transmission operators as applicable entities.

– Require reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities' necessary transaction modifications before implementation.

– Consider the suggestions made by EEI and TVA and address questions raised by Entergy and Northern Indiana as part of the standard development process.

INT-007-1 Interchange Confirmation

Unresolved Directives from FERC Order 693 – none

VRF Comment

– R1, 1.1, 1.3, 1.3.1, 1.3.2, 1.3.3, 1.3.4, 1.4 – administrative

INT-008-2 Interchange Authority Distributes Status

Directives from FERC Order 693

– Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

VRF Comments

– R1.1.1 & 1.1.2 – commercial and administrative

INT-009-1 Implementation of Interchange

Directives from FERC Order 693

– Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

INT-010-1 Interchange Coordination Exemptions

Directives from FERC Order 693

– Consider Northern Indiana's and ISO-NE's suggestions in the standards development process.

VRF Comments

– R1 & 3 – administrative

Attachment 2 – Interchange Subcommittee's Principles and Definitions for Dynamic Schedules and Pseudo-ties

Dynamic Schedules
A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between balancing areas. A dynamic schedule must not change a balancing area's jurisdiction; that is, the native balancing area continues to exercise operational jurisdiction over, and provides basic balancing area services to, the dynamically scheduled resources.

All dynamic schedules used to assign the control of generation, loads, or resources from one balancing area to another must meet the following requirements:

1. Telemetry
1.1. Appropriate telemetry for a dynamic schedule must be in place and incorporated by all affected balancing areas. Standards requirements associated with this should address appropriateness issues related to accuracy, sampling rate, etc. which would impact reliability. For example, the relationship of BAL-005-1 R10 and BAL-005-1, R16 should be confirmed.

2. Transmission Service
2.1. Prior to implementation of the dynamic schedule of load or generation, it is the obligation of each involved balancing area to ensure that the dynamic schedule is implemented such that the tariff requirements of the applicable transmission provider(s) are met, including applicable ancillary services and provision of losses.
2.2. If transmission service between the source and sink balancing areas is curtailed then the allowable range of the magnitude of the schedules between them, including dynamic schedules, must be curtailed accordingly. Since dynamic schedules are implemented in ACE via telemetry, curtailment of e-Tags associated with dynamic schedules must be complemented with appropriate adjustments to the telemetered values used in ACE to make the curtailment be physically implemented via ACE control action.

3. System Modeling
3.1. Each balancing area must ensure that the dynamic transfer of load or generation through a dynamic schedule is coordinated with the Reliability Coordinator(s) with responsibility over the native, attaining, and contract intermediary balancing areas so that the dynamic schedule can be properly implemented in the system modeling of the affected generation or load, and necessary data provision requirements are met. Coordination must include tagging of the resultant scheduled interchange for use by other transmission providers and balancing areas for system security analysis and calculation of ATC.
3.2. When a dynamic schedule is used to serve load within another balancing area, the balancing area where the load is electrically connected (native balancing area) must include that load in its balancing area load forecast and any subsequent reporting as needed. This is necessary because the system models must adequately capture the projected demand on the system (load forecast), and the projected supply (provided by the electronic tagging system).

4. Dynamic Schedule Coordination and Scheduling
4.1. Although implemented in the ACE via telemetry, implementation of a dynamic schedule for NERC-identified reliability analysis services must be through the use of an interchange transaction between balancing areas. As such, all dynamic schedules must be tagged and implemented in accordance with NERC Standards.

4.2. Energy exchanged between the source, sink, and intermediary balancing areas as a dynamic schedule is the metered or calculated (obtained by the integration of the dynamic schedule signal over the operating hour) energy for the loads and/or resources for the hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.
4.3. The native balancing area must ensure that agreements are in place defining the responsibility for providing applicable ancillary/interconnected operations services.
4.4. The drafting team should consider reliability impacts and draft appropriate standards related to how dynamic schedules are modeled from various perspectives such as level of detail (i.e. degree to which composite representation is allowed such as each generator having dynamic schedule or allowing a composite plant dynamic schedule) and use of block schedules to serve part of a dynamic schedule. In the latter case, although a single telemetered value may be used in the ACE for a load, it can be represented in the e-Tagging by a combination of one or more block schedules for part of the load and a dynamic schedule for the remainder to represent the dynamic nature of a load.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the dynamic schedule on a plan for how the balancing areas will operate during a loss of the dynamic schedule telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.
5.2. The native balancing area, attaining balancing area and intermediary balancing areas shall agree before implementation of the dynamic schedule upon a plan for how the load will be served during abnormal system conditions including periods of time when the transfer path between them is unavailable. The native balancing area, attaining control area and intermediary balancing areas shall also agree before implementation of the dynamic schedule as to how the generation serving the dynamic schedule will respond during abnormal system conditions, including periods of time when the transfer path between them is unavailable.

Pseudo-Ties
Pseudo-ties are often employed to assign generators, loads, or both from the balancing area to which they are physically connected into a balancing area that has effective operational control of them. Thus, pseudo-ties provide for change of balancing area jurisdiction from the native to the attaining balancing area and at the same time make the attaining balancing area provider of balancing area services. This methodology is also referred to as “AGC Interchange” or “Non-Contiguous Pool Tie.” In practice, pseudo-ties may be implemented based upon metered or calculated values. All balancing areas involved account for the power exchange and associated transmission losses as actual interchange between the balancing areas, both in their ACE equations and throughout all of their energy accounting processes.

All pseudo-ties used to assign generation, loads, or resources from the native balancing area to the attaining balancing area must meet the following requirements:
1. Telemetry
1.1. Appropriate telemetry must be in place and incorporated by all affected balancing areas.

2. Transmission Service
2.1. Prior to implementation of the dynamic transfer of load or generation by pseudo-tie, each involved balancing area shall ensure that the pseudo-tie is implemented such that the

tariff requirements of the applicable transmission provider(s), including applicable ancillary services and provision of losses, are met.
2.2. If transmission service between the native and attaining balancing areas is curtailed, then the allowable range of the magnitude of the pseudo-ties between them must be limited accordingly to these constraints. Since pseudo-ties are implemented in ACE via telemetry, appropriate adjustments must be made to the telemetered values used in ACE to make a curtailment be physically implemented via ACE control action.
2.3. Pseudo-ties must be implemented on firm transmission and are subject to curtailment on a pro rata basis with other firm transactions.

3. System Modeling
3.1. The assignment of load or generation into the control response of another balancing area must be appropriately captured in the IDC and security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators. It is the obligation of each balancing area to ensure that the dynamic transfer of load or generation by pseudo-ties is coordinated with the Reliability Coordinator(s) that have responsibility over the native, attaining, and contract intermediary balancing areas so that the pseudo-tie can be properly implemented in the system modeling of the generation or load affected, and necessary data provision requirements are met.
3.2. The attaining balancing area dynamically transferring load into its effective boundaries through a pseudo-tie shall ensure that load forecasts and subsequent balancing area reporting reflect the load incorporated within its balancing area boundaries.
3.3. If the reliability impact of the pseudo-tie cannot be accurately captured in the IDC and the security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators, the parties must implement the dynamic transfer either through use of a dynamic schedule, or through a combined implementation of pseudo-tie and dynamic schedule where the load or generation within the native balancing area is separately modeled in the IDC.
3.4. The drafting team should consider clarifying how pseudo-tie can be used in reliability analysis activities. For example, since they are not physical ties, should they be omitted from being used as part of a defined flowgate and in physical interface calculations yet be included in inadvertent calculations

4. Pseudo-Ties Coordination and Scheduling
4.1. Subsequent to moving load or resources into an attaining balancing area through pseudo-ties, all interchange transactions or other energy transfers to the loads or from the resources must be coordinated by the attaining balancing area.
4.2. The attaining balancing area assumes responsibility for balancing area services required by the assigned loads and/or resources. The attaining balancing area assumes all regulation, contingency reserves, and other balancing area responsibilities for the loads and/or resources in question.
4.3. Energy exchanged between the native and attaining balancing areas by the pseudo-tie method is accounted for by the associated revenue meter reading for the operating hour (if such meter exists at the dynamically assigned resource or load) or energy calculated by integrating the associated telemetered real-time signal over the operating hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie on a plan for how the balancing areas will operate during a loss of the pseudo-tie telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good

value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.
5.2. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie upon a plan for how the load will be served during abnormal system conditions including periods of time when the interconnection between them is lost. The native balancing area, attaining balancing area, and intermediary balancing areas shall also agree before implementation of the pseudo-tie how the entities will respond during abnormal system conditions, including periods of time when the connection between them is unavailable.

Dynamic Transfer Reference Document
The Drafting Team should take the existing Dynamic Transfer Reference Document, update it as necessary to reflect Functional Model terms and any changes necessary as a result of new requirements from the standards drafting resulting from this SAR and submit it for ballot as a formal reference document linked to those standards. This will provide the industry with a formal, official document to provide guidance on the implementation of dynamic transfers covered in the standards.

The Interchange Subcommittee recommends moving INT-001 standard requirement R.1. to a more appropriate INT standard such as INT-001 or INT-003.

Note: In addition to the above requirements, the NERC Glossary of Terms may need to be amended to include the following new or revised definitions:

ATTAINING BALANCING AREA — A balancing area bringing generation or load into its effective control boundaries through dynamic transfer from the Native Balancing area.

DYNAMIC SCHEDULE — A telemetered reading, or value that is updated in real-time and used as a schedule in the AGC/ACE equation of the affected balancing areas and the integration of which is treated as a schedule for interchange accounting purposes. To the extent that no associated energy metering equipment exists, the integration of the telemetered real time signal is used as a scheduled MWh value for interchange accounting purposes.

DYNAMIC TRANSFER — The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to implement a dynamic schedule or pseudo-tie.

INTEGRATION in the context of dynamic schedules and pseudo-ties means the value could be mathematically calculated or determined mechanically with a metering device.

INTERCONNECTED OPERATIONS SERVICE (IOS) — A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected bulk electric systems.

NATIVE BALANCING AREA — A balancing area from which a portion of its physically interconnected generation and/or load is assigned from its effective control boundaries through dynamic transfer to the attaining balancing area.

PSEUDO-TIE — A telemetered reading, or value that is updated in real time, representative of generation or load assigned dynamically between balancing areas and used as a tie line flow in the affected balancing areas' AGC/ACE equation, but for which no physical balancing area tie actually exists. To the extent that no associated energy metering equipment exists,

the integration of the telemetered real time signal is used as a metered MWh value for interchange accounting purposes.

Project 2008-12: Coordinate Interchange Standards

VRF and VSL Justifications for INT-004-3

VRF and VSL Justifications – INT-004-3, R1	
Proposed VRF	Lower
NERC VRF Discussion	Dynamic Schedules or Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring Arranged Interchanges is submitted, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method,

VRF and VSL Justifications – INT-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to submit a Request for Interchange.

VRF and VSL Justifications – INT-004-3, R2	
Proposed VRF	Lower
NERC VRF Discussion	Dynamic Schedules or Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-004-2, R2, which deals with updating tagging information and is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1-2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-004-3, R2	
Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to ensure the Confirmed Interchange or Pseudo-Tie was updated for the next available scheduling hour or future hours.

VRF and VSL Justifications – INT-004-3, R3	
Proposed VRF	Lower
NERC VRF Discussion	Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring Arranged Interchanges is submitted, is assigned a Lower VRF. Also, INT-004-3, R1, which deals with submittal of RFI, is also assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority did not implement or operate a Pseudo-Tie for that was included in the NAESB Electric Industry Registry publication.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	This guideline is not applicable because this is a new requirement.

VRF and VSL Justifications – INT-004-3, R3	
the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to implement or operate a Pseudo-Tie in the NASEB Electric Industry Registry publication.

Project 2008-12: Coordinate Interchange Standards

VRF and VSL Justifications for INT-010-2

VRF and VSL Justifications – INT-010-2, R1	
Proposed VRF	Lower
NERC VRF Discussion	After the fact submittal of a Request For Interchange (RFI) will not impact transmission congestion but may impact the ability to adequately assess transmission conditions for future hours. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-010-1, R1, which deals with submitting Arranged Interchange after the fact, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss.
Proposed Moderate VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time

VRF and VSL Justifications – INT-010-2, R1	
	more than 75 minutes, but not more than 90 minutes, following the resource loss.
Proposed High VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss.
Proposed Severe VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a RFI was submitted following the resource loss.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for this requirement mirror existing VSLs for this revised requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments	Guideline 2a: Not applicable. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.

VRF and VSL Justifications – INT-010-2, R1	
that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to ensure that the Request for Interchange was submitted, or for an RFI that was submitted with a start time more than 60 minutes following the resource loss.

VRF and VSL Justifications – INT-010-2, R2	
Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures that modified RFI is submitted for any Interchange that was modified at the direction of a Reliability Coordinator. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-010-1, R2, which deals with submitting a modified Arrange Interchange, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.

VRF and VSL Justifications – INT-010-2, R2	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-010-2, R2	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of ensuring that a Reliability Adjustment Arranged Interchange reflecting the modification was submitted within 60 minutes following the start of the modification.

VRF and VSL Justifications – INT-010-2, R3	
Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures that modified RFI is submitted for any Interchange that was modified at the direction of a Reliability Coordinator. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-010-1, R3, which deals with submitting a modified Arrange Interchange, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A

VRF and VSL Justifications – INT-010-2, R3	
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority did not ensure that a RFI was submitted within 60 minutes following the start of the scheduled Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned “Severe.” Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of	The VSL is assigned for a single instance of not ensuring that a RFI was submitted within 60 minutes following the start of the scheduled Interchange.

VRF and VSL Justifications – INT-010-2, R3	
Violations	

A. Introduction

1. **Title:** **Dynamic Interchange Transaction Modifications**
2. **Number:** INT-004-2
3. **Purpose:** To ensure Dynamic Transfers are adequately tagged to be able to determine their reliability impacts.
4. **Applicability**
   - **4.1.** Balancing Authorities
   - **4.2.** Reliability Coordinators
   - **4.3.** Transmission Operators
   - **4.4.** Purchasing-Selling Entities
5. **Effective Date:** August 27, 2008 (U.**S.)**

   NERC Board Approval: October 9, 2007

B. Requirements

R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.

R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs:

R2.1. The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±10%.

R2.2. The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±25 megawatt-hours.

R2.3. A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.

C. Measures

M1. The Sink Balancing Authority shall provide evidence that the responsible Purchasing-Selling Entity revised a tag when the deviation exceeded the criteria in INT-004 Requirement 2.

D. Compliance

1. **Compliance Monitoring Process**

   Periodic tag audit as prescribed by NERC. For the requested time period, the Sink Balancing Authority shall provide the instances when Dynamic Schedule deviation exceeded the criteria in INT-004 R2 and shall provide evidence that the responsible Purchasing-Selling Entity submitted a revised tag.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year without a violation from the time of the violation.

1.3. Data Retention

Three months.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Not specified.

2.2. Level 2: Not specified.

2.3. Level 3: Not specified.

2.4. Level 4: Not specified.

E. Regional Differences

1. None

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Board of Trustees Approval	Revised
2	October 9, 2007	Board of Trustees Approval (Removal of WECC Waiver)	Revised
2	July 21, 2008	FERC Approval	Revised

A. Introduction

1. **Title:** **Interchange Coordination Exemptions**

2. **Number:** **INT-010-1**

3. **Purpose:** Allow certain types of Interchange schedules to be initiated or modified by reliability entities, and to be exempt from compliance with other Interchange Standards under abnormal operating conditions.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Reliability Coordinator.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required.

R2. For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event.

R3. For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event.

C. Measures

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence it submitted Arranged Interchange per Requirement 1.

M2. The Reliability Coordinator that directs a modification to an existing Interchange shall have evidence that a directive was issued to submit the Arranged Interchange in accordance with Requirement 2.

M3. The Reliability Coordinator that directs the initiation of a new Interchange shall have evidence that a directive was issued to submit the Arranged Interchange in accordance with Requirement 3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last noncompliance to R1, R2, or R3.

1.3. Data Retention

The Balancing Authority and Reliability Coordinator shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

Each Balancing Authority and Reliability Coordinator shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Balancing Authorities and Reliability Coordinators, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authority and Reliability Coordinator shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate a Balancing Authority or Reliability Coordinator acted in compliance with INT-010. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicates a Balancing Authority or Reliability Coordinator failed to act in compliance with INT-010.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 One occurrence of not submitting an Arranged Interchange as described in R1.

2.1.2 One occurrence of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.2. Level 2: There shall be a level two non-compliance if either of the following conditions is present:

2.2.1 Two occurrences of not submitting an Arranged Interchange as described in R1.

2.2.2 Two occurrences of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.3. Level 3: There shall be a level three non-compliance if either of the following conditions is present:

2.3.1 Three occurrences of not submitting an Arranged Interchange as described in R1.

2.3.2 Three occurrences of not directing the submittal of a new or modified Arranged Interchange as described in R2 or R3.

2.4. Level 4: There shall be a level three non-compliance if any of the following conditions is present:

2.4.1 Four or more occurrences of not submitting an Arranged Interchange as described in R1.

2.4.2 Four or more occurrences of not directing the submittal of a new or modified Arranged Interchange as described in Requirements 2 or 3.

2.4.3 No evidence provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement Notice

Project 2008-12 Coordinate Interchange Standards Two Definitions

Additional Ballots Now Open Through January 27, 2014

Please note that two Project 2008-12 Definitions are open for ballot beginning today and closing at 8 p.m. Eastern on Monday, January 27, 2014.

Now Available

A ballot of two definitions (**Request for Interchange** and **Arranged Interchange**) associated with Project 2008-12 Coordinate Interchange Standards is open through **8 p.m. Eastern on Monday, January 27, 2014.**

Additional ballots for **INT-004-3 (Dynamic Transfers) and INT-010-2 (Interchange Initiation and Modification for Reliability)**, two definitions, and non-binding polls of the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) associated with the two standards are now open through **8 p.m. Eastern on Wednesday, January 22, 2014.**

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standards, definitions, and non-binding polls of the VRFs and VSLs by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, the standards and definitions will proceed to a final ballot.

Standards Development Process

The Standards Processes Manual 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 Wendy Muller, Standards Development Administrator, or at 404-446-2560.

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Standards Announcement

Project 2008-12 Coordinate Interchange Standards INT-004-3, INT-010-2, and Definitions

Formal Comment Period: December 9, 2013 – January 22, 2014

Upcoming:
Additional Ballots and Non-Binding Polls: January 10-22, 2014

Now Available

A 45-day formal comment period for **INT-004-3, INT-010-2, and the revised definitions for Request for Interchange and Arranged Interchange** is now open through **8 p.m. Eastern on Wednesday, January 22, 2014.**

INT-006-4, INT-009-2, INT-011-1, and 11 additional definitions earned stakeholder approval in the last ballot. The Coordinate Interchange Standard Drafting Team did not make any substantive changes to these standards or definitions based on stakeholder comments, and they will be posted for final ballot this week.

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Wednesday, January 22, 2014.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

Additional ballots for the two standards, two definitions, and non-binding polls of the Violation Risk Factors and Violation Severity Levels associated with the two standards will be conducted January 10-22, 2014.

Standards Development Process

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Standards Announcement

Project 2008-12 Coordinate Interchange Standards
INT-004-3, INT-010-2, and Definitions

Formal Comment Period: December 9, 2013 – January 22, 2014

Upcoming:
Additional Ballots and Non-Binding Polls: January 10-22, 2014

Now Available

A 45-day formal comment period for **INT-004-3, INT-010-2, and the revised definitions for Request for Interchange and Arranged Interchange** is now open through **8 p.m. Eastern on Wednesday, January 22, 2014.**

INT-006-4, INT-009-2, INT-011-1, and 11 additional definitions earned stakeholder approval in the last ballot. The Coordinate Interchange Standard Drafting Team did not make any substantive changes to these standards or definitions based on stakeholder comments, and they will be posted for final ballot this week.

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Wednesday, January 22, 2014.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

Additional ballots for the two standards, two definitions, and non-binding polls of the Violation Risk Factors and Violation Severity Levels associated with the two standards will be conducted January 10-22, 2014.

Standards Development Process

The Standards Processes Manual 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.

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Standards Announcement

Project 2008-12 Coordinate Interchange Standards
Two Definitions

Additional Ballot Results

Now Available

An additional ballot of two definitions (**Request for Interchange** and **Arranged Interchange**) associated with Project 2008-12 Coordinate Interchange Standards concluded at **8 p.m. Eastern on Wednesday, January 29, 2014.**

The definitions achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

Ballot Results
Quorum /Approval
76.12% / 92.17%

Background information for this project can be found on the project page.

Next Steps

The definitions will be posted for a final ballot. If they are approved by the ballot pool, they will be submitted to the NERC Board of Trustees for adoptions and then filed with applicable government authorities.

Standards Development Process

The Standard Processes Manual 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 Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

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-Ballot Pools
-Current Ballots
-Ballot Results
-Registered Ballot Body
-Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2008-12 Definitions
Ballot Period:	1/16/2014 - 1/29/2014
Ballot Type:	**Additional Ballot**
Total # Votes:	255
Total Ballot Pool:	335
Quorum:	**76.12 % The Quorum has been reached**
Weighted Segment Vote:	92.17 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	90	1	53	0.914	5	0.086	0	14	18
2 - Segment 2	8	0.4	4	0.4	0	0	0	2	2
3 - Segment 3	79	1	48	0.96	2	0.04	0	8	21
4 - Segment 4	24	1	12	0.923	1	0.077	0	5	6
5 - Segment 5	72	1	36	0.857	6	0.143	0	10	20
6 - Segment 6	49	1	29	0.853	5	0.147	0	5	10
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.2	2	0.2	0	0	0	0	2
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	7	0.6	6	0.6	0	0	0	1	0
Totals	**335**	**6.3**	**191**	**5.807**	**19**	**0.493**	**0**	**45**	**80**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam		

1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to the comments submitted on behalf of PPL NERC Registered Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan	Abstain	

		Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik		
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENT RECEIVED
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	

3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Abstain	
4	Consumers Energy Company	Tracy Goble		
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Tallahassee	Karen Webb		
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	

5	Detroit Renewable Power	Marcus Ellis	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric Co)
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	

5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Abstain	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young		
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA Comments)
6	Lincoln Electric System	Eric Ruskamp		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric Co)
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	

6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Abstain	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy

404.446.2560 voice : 404.446.2595 fax
Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Standards Announcement

Project 2008-12 Coordinate Interchange Standards

Additional Ballot and Non-Binding Poll Results

Now Available

Additional ballots for **INT-004-3 (Dynamic Transfers) and INT-010-2 (Interchange Initiation and Modification for Reliability)** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Wednesday, January 22, 2014 and Friday, January 24, 2014 respectively**.

The standards achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

	Ballot Results	Non-Binding Poll Results
	Quorum /Approval	Quorum/Supportive Opinions
INT-004-3	75.22% / 81.19%	76.14% / 82.95%
INT-010-2	75.22% / 90.23%	76.47% / 89.51%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

Standards Development Process

The Standard Processes Manual 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 Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2008-12 INT-004-3
Ballot Period:	1/10/2014 - 1/22/2014
Ballot Type:	**Additional Ballot**
Total # Votes:	252
Total Ballot Pool:	335
Quorum:	**75.22 % The Quorum has been reached**
Weighted Segment Vote:	81.19 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	90	1	49	0.817	11	0.183	0	8	22
2 - Segment 2	8	0.5	4	0.4	1	0.1	0	2	1
3 - Segment 3	79	1	41	0.788	11	0.212	1	6	20
4 - Segment 4	24	1	11	0.846	2	0.154	0	2	9
5 - Segment 5	72	1	33	0.733	12	0.267	0	8	19
6 - Segment 6	49	1	30	0.75	10	0.25	1	1	7
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.1	1	0.1	0	0	0	0	3
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	7	0.5	5	0.5	0	0	0	1	1
Totals	**335**	**6.2**	**175**	**5.034**	**47**	**1.166**	**2**	**28**	**83**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dayton Power & Light Co.	Hertzel Shamash	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke		
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
				SUPPORTS THIRD

1	Lakeland Electric	Larry E Watt	Negative	PARTY COMMENTS - (Florida Municipal Power Agency)
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric Co)
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection)
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL NERC Registered Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Adopt PJM comments)
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		

1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection)
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	NO COMMENT RECEIVED - (Seattle City Light)
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM) - (Pepco Holdings Inc & Affiliates)
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		

3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman		
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENT RECEIVED
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Abstain	
4	Consumers Energy Company	Tracy Goble	Affirmative	
				SUPPORTS THIRD

4	Cowlitz County PUD	Rick Syring	Negative	PARTY COMMENTS - (Russell Noble)
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews		
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida

				Municipal Power Agency)
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric Co)
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (adopt PJM's comments)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	COMMENT RECEIVED
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support someone else's comment: Thomas Foltz – American Electric Power)

6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	NO COMMENT RECEIVED
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA Comments)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel		
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (adopt PJM's comments)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Negative	COMMENT RECEIVED
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
	Western Area Power Administration - UGP			

6	Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS-Alice Ireland (Murdock), Xcel Energy
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy
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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2008-12 INT-010-2
Ballot Period:	1/10/2014 - 1/22/2014
Ballot Type:	**Additional Ballot**
Total # Votes:	252
Total Ballot Pool:	335
Quorum:	**75.22 % The Quorum has been reached**
Weighted Segment Vote:	90.23 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	90	1	51	0.911	5	0.089	0	13	21
2 - Segment 2	8	0.5	4	0.4	1	0.1	0	2	1
3 - Segment 3	79	1	44	0.978	1	0.022	1	13	20
4 - Segment 4	24	1	9	0.9	1	0.1	0	5	9
5 - Segment 5	72	1	34	0.829	7	0.171	0	11	20
6 - Segment 6	49	1	31	0.886	4	0.114	1	6	7
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.1	1	0.1	0	0	0	0	3
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	7	0.4	4	0.4	0	0	0	2	1
Totals	**335**	**6.1**	**179**	**5.504**	**19**	**0.596**	**2**	**52**	**83**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana		
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke		
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
				SUPPORTS

1	Lakeland Electric	Larry E Watt	Negative	THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	

2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	NO COMMENT RECEIVED - (Seattle City Light)
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Abstain	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman		
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	

3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Abstain	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Abstain	
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews		
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	

5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		

5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	NO COMMENT RECEIVED
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA Comments)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel		
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	

6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Non-Binding Poll Results

Project 2008-12 INT-004-3

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2008-12 INT-004-3
Poll Period:	1/10/2014 - 1/24/2014
Total # Opinions:	233
Total Ballot Pool:	306
Ballot Results:	76.14% of those who registered to participate provided an opinion or an abstention; 82.95% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dayton Power & Light Co.	Hertzel Shamash	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
1	Deseret Power	James Tucker		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	

1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke		
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey		

1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL NERC Registered Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		

NERC

2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	

3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Abstain	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENT RECEIVED
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Russell Noble)
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews		
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Abstain	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED

5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric Co)
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	

5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Abstain	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support someone else's comment: Thomas Foltz – American Electric Power)
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA Comments)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	

6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel		
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2008-12 INT-010-2

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2008-12 INT-010-2
Ballot Period:	1/10/2014 - 1/24/2014
Total # Opinions:	234
Total Ballot Pool:	306
Ballot Results:	76.47% of those who registered to participate provided an opinion or an abstention; 89.51% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinion	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana		
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	

1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke		
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu		
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan		

1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	

3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Abstain	
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jea)
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Abstain	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	

3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Abstain	
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews		
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	

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4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Abstain	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		

5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	

6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA Comments)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel		
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Roger C Zaklukiewicz		

8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (23 Responses)
Name (10 Responses)
Organization (10 Responses)
Group Name (13 Responses)
Lead Contact (13 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (1 Responses)
Comments (23 Responses)
Question 1 (21 Responses)
Question 1 Comments (22 Responses)
Question 2 (16 Responses)
Question 2 Comments (22 Responses)
Question 3 (0 Responses)
Question 3 Comments (22 Responses)
Question 4 (0 Responses)
Question 4 Comments (22 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
Yes.
Yes.
Group
Dominion NERC Compliance Policy
Randi Heise
Yes
Yes
Yes.
Individual
Russell Noble
Cowlitz PUD
No
Cowlitz disagrees with the SDT dismissal of comments submitted by Seattle City Light.
Cowlitz disagrees with the SDT's dismissal of comments submitted by Seattle City Light and NextEra.
Individual
Michael Falvo
Independent Electricity System Operator
Yes

Yes
The revised R1 is unclear on the condition under which a BA needs to submit an RFI no more than 60 minutes beyond the resource loss. The phrase “or other reliability needs” R1 seems to be out of place and subject to a number of possible interpretations. R1 stipulates that: R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. We ask the SDT to revise this to more clearly convey the intent.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
Yes
INT-004-3 R1: How do entities know the forecast for submitted pseudo-ties included in congestion management? In order to add bounds to the alternate method, we request that the SDT consider adding the following (bolded section) to R1: Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method that provides a projection of usage of the Pseudo-Tie to the Transmission Operator. INT-004-3 R3: We request that the SDT consider adding the following (bolded section) to R3 in order to clarify roles and responsibilities: Each Purchase-Selling Entity is responsible for registering Pseudo-Ties in the NAESB Electronic Industry Registry publication. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures.
Yes
Yes.
Yes.
Individual
Shirley Mayadewi
Manitoba Hydro
No
(1) R1 – We note the addition of language by the SDT in the Rationale for R1 with respect to a situation where no forecast may be available. It is Manitoba Hydro’s view that the text currently contained in the Rationale with respect to what is required to be in an RFI belongs more appropriately in the body of the standard itself rather than in a Rationale. Our understanding is that the content of the Rationale text boxes will be moved to the Application Guidelines section of the standard upon approval of the standard; the content of the Application Guidelines section is not one of the mandatory or enforceable components of a reliability standard even though they may be looked to for guidance by entities and auditors. This particular Rationale goes beyond an explanation by the SDT of why the requirement/part is required, or why the wording changes are appropriate, and provide specific direction as to the appropriate inclusion in the RFI; something that is missing in the body of the standard itself. (Law, Export Operations, RCD) (2) R1 – The additional language added by the SDT, while it does attempt to address circumstances where no forecast is available, still leaves some uncertainty as to the appropriate volume to be tagged in an RFI. Suggested alternative language to make it abundantly clear would be: “If no forecast is available for the Dynamic Schedule, the energy profile in the Request for Interchange should be the expected maximum value of the Dynamic Schedule.”
Yes
Yes
Although Manitoba Hydro supports the proposed changes, we have the following comments: (1) R1 - unclear what the phrase ‘other reliability needs’ is meant to cover. The remainder of the standard only talks about resource loss and doesn’t address ‘other reliability needs’. (2) M1 – should include greater detail from requirement language. i.e. “The Balancing Authority that uses its energy sharing agreement where the duration of use exceeds 60 minutes from the resource loss shall have….” (3) M3 – RFI is used here, whereas Request for Interchange is used elsewhere. If the RFI

acronym is desired, Request for Interchange should be defined as such at its first use and RFI used consistently throughout. (4) VSLs, R1 – RFI is used here, whereas Request for Interchange is used elsewhere. If the RFI acronym is desired, Request for Interchange should be defined as such at its first use and RFI used consistently throughout. (5) VSLs, R2 - RFI is used here, whereas Request for Interchange is used elsewhere. If the RFI acronym is desired, Request for Interchange should be defined as such at its first use and RFI used consistently throughout. Also, the words 'reflecting an Interchange Schedule' should be inserted following 'Request for Interchange'. 'The' scheduled interchange should be 'that' scheduled interchange.
Individual
Paul Kerr
Shell Energy North America
No
Shell Energy North America disagrees with the comments filed and the decision to revert the applicability of INT-004 to Purchasing Selling Entities. The wording in the proposal at R1 retains the condition existing in the currently approved INT-001 standard that the subject transactions are taking place to serve load. R2 is entirely contingent on R1 and continues the misplaced applicability to PSEs. This load serving aspect remains the impetus to the belief by some stakeholders that this type of activity has reliability impacts, rather than being the business process requirements that they truly are. If the R1 and R2 requirements of the standard are to be maintained, the applicability should be on Load Serving Entities as originally proposed in the this Project. LSEs engaging in such transactions are the responsible party, and if the LSE is not also a PSE, a reliability gap will be created by setting the applicability to PSEs.
Individual
Anthony Jablonski
ReliabilityFirst
No
During the last comment period, ReliabilityFirst questioned the term "on-time" within Requirement R1. ReliabilityFirst appreciates the SDT response that "The term 'on-time' is addressed in the timing tables contained in INT-006". ReliabilityFirst believes a reference to the INT-006 standard should be placed in the INT-004-3 standard. Absent a reference to the INT-006 standard, those not familiar with the table in the INT-006 standard may not understand the meaning of the term "on-time" and thus cause both reliability and compliance complications.
During the last comment period, ReliabilityFirst requested clarification of the term "energy sharing agreement" within Requirement R1. ReliabilityFirst appreciates the SDT response (and updated rationale box within the standard) that stated "There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled." ReliabilityFirst does have a concern that once the standard is approved, the rational box will be removed from the standard and the clarification of this term may be lost. ReliabilityFirst recommends including a portion of the rational into the requirement as follows: "The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement [(regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled)] or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted…"
Individual
Thomas Foltz
American Electric Power
Yes
Though we welcome the addition of the PSE in the applicability section, we believe the LSE should be retained rather than replacing it entirely. In some non-RTO areas for example, there is the potential that it is the LSE who would be tasked with performing this work. Our negative vote on this standard is solely driven by the removal of the LSE in the Applicability section. We believe that the BA, PSE, *and* LSE should all be included.
Yes
Yes.

Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: Louisville Gas and Electric Company and Kentucky Utilities Company; PPL EnergyPlus, LLC; PPL Electric Utilities Corporation; PPL Generation, LLC, PPL Susquehanna, LLC and PPL Montana, LLC on behalf of its NERC registered entities. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. It is unclear in R1 as to which BA's congestion management procedures the information for the Psuedo-Tie is to be included, the Source BA's or the Sink BA's (or both).
No
The proposed defined term Arranged Interchange is not needed as it is effectively the same as (and redundant to) Request for Interchange. Each is a set of data that has been submitted for approval. The verb "submitted" implies "submitted for approval" in the definition of Request for Interchange. To clarify this issue, the SDT should revise the definition of Request for Interchange to the following: A collection of data as defined in the NAESB Business Practice Standards, that has been initiated or revised and submitted for approval to the Sink Balancing Authority for the purpose of implementing bilateral Interchange between Source and Sink Balancing Authorities or an energy transfer within a single Balancing Authority.
No. See comment to question 2. It is unclear how the proposed change in the definition of Arranged Interchange would impact other standards, particularly MOD-004-1 R11 and R12. Therefore, remove the proposed changes to this definition from the project and use only the one term – Request for Interchange.
Yes.
Group
Oklahoma Gas and Electric Co
Donald Hargrove
No
INT-004-3 R3 requires BA's to only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry. This is clearly a Commercial/Business practice issue. From a reliability perspective if the RC, PC and TSP are informed, a BA should be able to implement or operate a Pseudo-Tie. Requiring administrative reporting to a non-reliability (commercial / business practice) entity is not appropriate for the Reliability Standards. This requirement falls clearly with Criteria A and Criteria B6 of the paragraph 81 criteria and should be removed from the draft Standard. Criterion A (Overarching Criterion) The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES. Criteria B (Identifying Criteria) B6. Commercial or Business Practice The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues. This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.
No
The definition of "Request for Interchange," references the NAESB Business Practice Standards. I cannot submit an affirmative vote because I do not have access to the NAESB Business Practice Standards; I have no idea what constitutes the data defined therein. As long as the NAESB standards are not open and freely available like the NERC Standards, I cannot in good conscience vote affirmative on a NERC Reliability Standard or NERC Glossary Definition that references them.
Yes.
Yes.
Individual
Alice Ireland
Xcel Energy
No
Xcel Energy is voting negative b/c we do not agree with the inclusion of Pseudo-Ties. Here are our specific issues with each requirement: R1- Pseudo–Ties do not have tags, they are metered into the BA as part of the NAI term of the ACE equation. R2- All references to Pseudo-Ties should be removed. This requirement is just for "Confirmed Interchange" that is a Dynamic Schedule, which is part of the NSI term of the ACE equation. R3- This requirement should specify a minimum level before registration of a Pseudo-Tie is required. We feel Pseudo-Ties should only be registered if they are in a congested transmission area.

Group
Duke Energy
Michael Lowman
No
Duke Energy suggests the following change to R3 of INT-004-3, “Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. “ Since NAESB will define the requirements for Pseudo-Tie registration, there is no need to add “in support of congestion management procedures.” Based on the Purpose of the standard, as written, our interpretation is that this is already understood.
Yes
Yes. Duke Energy supports the changes made by the SDT.
Yes. Duke Energy supports the changes made by the SDT.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
Yes
Yes
Yes
Individual
Chris Scanlon
Exelon
Yes
We support the combination of INT-001 and INT-003 however, the registration of a Pseudo – Tie in NAESB must be transparent to all parties. Currently, that information is not readily available.
Group
Florida Municipal Power Agency
Frank Gaffney
Our comments from last November’s posting were not addressed. In summary, FMPA believes these standards are not important for reliability, are commercial in nature, and are duplicative of NAESB standards and BAL standards. Please refer to our comments submitted on November 13, 2013.
Please see FMPA comments to Question 1.
Please see FMPA comments to Question 1.
Please see FMPA comments to Question 1.
Group
SERC OC Review Group
Rene Free
Yes
We respectfully submit a change to R3 Sever VSL to further align with R3. Current Language: The Balancing Authority did not implement or operate a Pseudo-Tie that was included in the NAESB Electric Industry Registry publication. Proposed Language: The Balancing Authority DELETE: “did not” implement Add: “ed” or operate Add: “d”a Pseudo-Tie that was Add: “Not” included in the NAESB Electric Industry Registry publication.

Yes
Yes
Yes. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Group
ISO/RTO Council Standards Review Committee
Greg Campoli
Yes
Yes
Yes
Yes
Group
ACES Standards Collaborators
Jason Marshall
No
(1) We do not support this concept as a reliability standard and believe it should be retired and transferred to NAESB. The purpose statement of the standard is to ensure that Dynamic Schedules and Pseudo Ties are “accounted for appropriately in congestion management procedures.” While this is an important business practice to ensure the schedules are treated equitably, it is not a reliability issue and should not be in a NERC standard. Congestion management procedures are designed and intended to ensure the transmission service is curtailed based on its priority so that lower priority service does not supersede higher priority service. It designed to comport with FERC pro forma tariff requirements for the treatment of various levels of transmission service. A reliability entity such as a BA, TOP, or RC must still be able to reduce loading via other methods (e.g. manual redispatch or transmission reconfiguration) in addition to congestion management. While some entities (e.g. ISO and RTOs) have designed very effective congestion management procedures that are defined by their tariffs through the use of locational marginal pricing (LMP), they are still required to have other capabilities to reduce loading(e.g. manual redispatch or transmission configuration). Thus, congestion management is clearly a business practice designed to facilitate the orderly curtailment of transmission service so that lower priority service is curtailed first. Congestion management is a tool to facilitiate management of transmission service curtailments. It is not a reliability tool. Thus, a NERC standard designed to ensure that Dynamic Schedules and Pseudo-Ties are tagged is an important business practice but is not required for reliability. This standard should be retired and moved to NAESB.
No
(1) We disagree with the inclusion of intra-BA schedules because there is a direct conflict with other NERC glossary terms. “Interchange” is defined in the NERC glossary as “Energy transfers that cross Balancing Authority boundaries.” Thus, “Interchange” only deals with external transfers and does not include intra-BA schedules. We think it will be confusing to define a “Request for Interchange” inconsistently with “Interchange” and that they will be used inconsistently as documented in our response to question 4 regarding INT-010-2 R3. “Request for Interchange” should literally be a request to schedule the NERC term “Interchange,” which would be for energy transfers that cross BA boundaries. The proposed definition of “Request for Interchange” conflicts with the existing definition of “Interchange”and needs to be modified so they are both aligned.
We disagree with the inclusion of the clause “initial or revised.” Does the definition of “Request for Interchange” include initial requests and revisions to those requests? If so, then the inclusion of the clause “initial or revised” is superfluous. If not, then the definition for Arranged Interchange is implying that “Request for Interchange” can include revisions incorrectly. Either way, the clause should be removed.
(1) “Request for Interchange” is used inconsistently with “Interchange” in R3. Request for Interchange includes intra-BA transfers. However, by definition, Interchange does not since it only includes “energy transfers that cross Balancing Authority boundaries.” Thus, the requirement is written incorrectly when the Request for Interchange is for an intra-BA energy transfers. As an example, R3 requires that a Request for Interchange should be submitted within 60 minutes of the “start of the scheduled Interchange.” If the Request for Interchange is for an intra-BA energy transfer, to which Interchange schedule does the requirement refer ? It cannot refer to the Interchange schedule associated with the Request for Interchange, because the definition Interchange does not include intra-BA schedules. The conflict of the NERC defined terms “Request for Interchange” and “Interchange” has created ambiguity and uncertainty in the requirements and needs to be resolved. (2) Thank you for the opportunity to comment.

Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC OC
Group
Bonneville Power Administration
Jamison Dye
Yes
BPA supports the proposed changes to the draft INT-004-3 except for the Rational in R1. The Rationale starting with the second sentence is not valid for R1. R1 is regarding when a PSE must submit an RFI for Dynamic Transfer. How information is utilized does not belong in a rationale for such a requirement. The second and third sentence in Rational R1 should be removed. The second sentence is unclear as to what is meant by “max transaction profile”. E-tags do not have a “transaction profile”. The third sentence in the rationale implies that if a forecast is used, the transmission profile can be exceeded. In the Table of Compliance Elements, the last sentence of the Severe VSL description for R1 ends with a comma. Assuming more verbiage does not follow the comma but is not visible in the table, the comma should be replaced with a period. Dynamic Transfer is a defined NERC Glossary term and as such, BPA suggests that the draft team capitalize the term if its use is intended to align with the NERC definition.
Yes
BPA supports the proposed changes to the Request for Interchange definition.
BPA supports the proposed changes to the Arranged Interchange definition.
BPA supports the proposed changes to the draft INT-010-2 with the following comment: Dynamic Transfer is a defined NERC Glossary term and as such, BPA suggests that the draft team capitalize the term if its use is intended to align with the NERC definition.
Group
SPP Standards Review Group
Robert Rhodes
Yes
While we have no issues with the proposed changes to the most recent draft that has been posted, in this reading we did note a few items that we missed in previous readings of the standard. Most of these items are minor with the exception of an item regarding the Severe VSL for R3. This is a significant item and needs to be corrected in the proposed draft in order for us to continue to support the proposed standard. We recommend modifying the Severe VSL for R3 to read: ‘The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.’ This wording is more on-point since the requirement does not require Balancing Authorities to implement or operate all Pseudo-Ties in the NAESB Registry but restricts the Balancing Authority to only implement or operate those Pseudo-Ties which are included in the Registry. Capitalize Dynamic Transfer throughout the Background and the Application Guidelines sections since the term is in the Glossary of Terms. Use a lower case ‘for’ in ‘Request for Interchange’ in R2. Capitalize Frequency Bias Setting, Frequency Bias and Dynamic Schedule in the table in the Application Guidelines on Page 9. We suggest modifying the first sentence under the General Considerations for Curtailments of Dynamic Transfers section in the Application Guidelines to read: ‘The unique handling of Curtailments of Dynamic Transfers is described in NERC’s Dynamic Transfer Reference Guidelines, Version 2.’ Capitalize ‘Curtailment’ in the paragraph under For Dynamic Schedules in the Application Guidelines. We suggest modifying the last paragraph on Page 9 of the Application Guidelines to read: ‘Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.’ Use a lower case ‘signal’ in Dynamic Transfer signal in the last paragraph of the Application Guidelines on Page 10.
Yes
Yes
Yes While we have no issues with the proposed changes to the most recent draft that has been posted, in this reading we did note a few items that we missed in previous readings of the standard. Most of these items are minor with the exception of items in the Severe VSL for R1 and in the Compliance 1.2 Evidence Retention section. These are significant items and need to be corrected in the proposed draft in order for us to maintain our support for the proposed standard. RFIs are only required when an energy sharing agreement is used for more than 60 minutes. The latter portion of the Severe VSL for R1 (after the OR) is currently written such that a Balancing Authority would be non-compliant if it failed to submit a RFI regardless of the length of time the energy sharing agreement was utilized. We recommend inserting ‘…when the use of the energy sharing agreement exceeded 60 minutes…’ at the end of the VSL.

Delete '…and Transmission Service provider…' from the Compliance 1.2 Evidence Retention section. The Balancing Authority is the only applicable entity listed in the standard. In that same sentence, insert '(CEA)' following Compliance Enforcement Authority since CEA is used later in this section. Capitalize 'schedule' in Interchange Schedule in R3 and M3. It is a defined term in the Glossary of Terms. The Application Guidelines were not included in the clean version of the standard. Capitalize Dynamic Transfer throughout the Application Guidelines section since it is a defined term in the Glossary of Terms. Modify the first sentence in the Application Guidelines such that it reads the same as we suggested in INT-004-3. 'The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.' Also as in INT-004-3, we suggest modifying the next to last paragraph in the Application Guidelines to read: 'Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.'
Individual
Russell Noble
Cowlitz PUD
No
The Standard mixes applicability in the Requirement. Please state applicability in Section 4.
Yes
Yes
Abstain

Note: ISO RTO Council Standards Review Committee (SRC) comments above for Question 1: PJM does not support the response.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2008-12 Coordinate Interchange Standards

The Project 2008-12 Drafting Team thanks all commenters who submitted comments on the draft INT-004-3 and INT-010-2 standards. These standards were posted for a 45-day public comment period from December 12, 2013 through January 22, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 24 sets of comments, including comments from approximately 91 different people from approximately 57 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

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, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration

The CISDT considered each comment submitted by stakeholders. The summary of the consideration of those comments follows.

INT-004-3

Many stakeholders agreed with the revisions to INT-004-3. Several stakeholders suggested clarifying edits with which the drafting team agreed. The drafting team made the following revisions to INT-004:

- Capitalized "Dynamic Transfer" throughout for consistency.
- Added a footnote to "on-time" in Requirement R1 to point to the timing tables in INT-006-4.
- Replaced "For" with "for" in Requirement R2 (Request for Interchange).
- Removed the "," at the end of the Severe VSL for R1 and replaced it with a "."
- Capitalized Frequency Bias, Frequency Bias Setting in the table in the Guidelines and Technical Basis section.
- Reworded two sentences in the Guidelines and Technical Basis section for clarity.

A couple of commenters suggested improvements to the Severe VSL for Requirement R3. The existing VSL reads: "The Balancing Authority did not implement or operate a Pseudo-Tie that was included in the NAESB

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Electric Industry Registry publication." The language of the requirement is for the Balancing Authority to only implement or operate a Pseudo-Tie that is registered. The CISDT has revised the VSL as suggested to: "The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication."

A couple of commenters suggested the addition of the LSE as an applicable entity in addition to the PSE. The CISDT notes that having multiple entities responsible for the same requirement will lead to confusion which could potentially create a reliability gap if each entity assumed that the other entity was handling the responsibility. If the PSE is the entity responsible that any PSE that is taking this action, even if not registered as an LSE, is still the responsible entity.

A few commenters had questions or concerns around the registration of Pseudo-Ties. Creating a formal registration process creates a clear mechanism by which all entities are informed and can account for Pseudo-Ties in congestion management procedures. Inclusion of Pseudo-Ties in congestion management procedures will need to be determined on a case by case basis, as each Pseudo-Tie configuration is unique. If all entities do not agree on the 'setup' during registration, then the Pseudo-Ties would not become implemented. While NAESB business practices are commercial in nature, the information in the EIR is a common tool used by both business practice and reliability tools. As such, the committee that supports this tool is a joint NERC and NAESB subcommittee. The registration process has yet to be detailed and it is possible that process to identify how the Pseudo-Tie is handled in congestion management procedures. The CISDT encourages all entities to participate in the development of the Pseudo-Tie registration in NAESB.

Request for Interchange (RFI)

The majority of commenters agreed with the proposed revisions to the definition of Request for Interchange (RFI). No changes were made to the definition as a result of comments received.

One commenter suggested that the proposed defined term Arranged Interchange is not needed as it is effectively the same as (and redundant to) Request for Interchange. The CISDT disagrees that the two terms are redundant. An RFI is a collection of data whereas Arranged Interchange is a state where the RFI has been submitted. These definitions align with NAESB Business Practices definitions and the NERC Interchange Reference Guidelines, version 2.

Another commenter noted that the definition of Request for Interchange references the NAESB Business Practice Standards and they are not publicly available. The CISDT notes that NAESB business practices are available to the public for a fee. FERC has ruled in the past that this is a reasonable practice.

One stakeholder disagreed with the inclusion of intra-BA schedules in the definition because there is a direct conflict with other NERC glossary terms. The CISDT does not believe that there is a conflict with other terms and notes that this was added to the definition to address a FERC Order 693 directive.

Arranged Interchange

The majority of commenters agreed with the proposed revisions to the definition of Arranged Interchange. No changes were made as a result of comments received.

One commenter was unclear how the proposed change in the definition of Arranged Interchange would impact other standards, particularly MOD-004-1, R11 and R12. The revisions to this defined term do not change the intent of the requirements or defined terms in which it is used. The revisions provide additional clarity for these requirements and defined terms.

One commenter disagreed with the inclusion of the clause "initial or revised". The CISDT notes that this is included in the existing, approved definition because Arranged Interchange may be revised and the team believes that this clarification is an improvement to the definition.

INT-010-2

Most stakeholders agreed with the revisions to INT-010-2. Several stakeholders suggested clarifying edits with which the drafting team agreed. The drafting team made the following revisions to INT-010:

- Added the Guidelines and Technical Basis Section to the clean version of the standard (it was in the redline version but inadvertently omitted here).
- Revised "RFI" to "Request for Interchange" for consistency throughout.
- Added "when the use of the energy sharing agreement exceeded 60 minutes." To the VSLs for R1 to clarify that an RFI does not need to be submitted unless this condition is met. This matches the language of the requirement.
- Capitalized "Dynamic Transfer" throughout for consistency.
- Reworded two sentences in the Guidelines and Technical Basis section for clarity.
- Removed Transmission Service Provider from section 1.2, Evidence Retention.
- Added "(CEA)" after "Compliance Enforcement Authority" in section 1.2, Evidence Retention.
- Capitalized "Schedule" in the term "Interchange Schedule".

Two stakeholders questioned the use of the phrase "or other reliability needs" within Requirement R1. As this requirement relates to energy sharing agreements, the CISDT believes that the content of those agreements will address the "other reliability needs" and that the drafting team is unable to develop a comprehensive list of what those agreements might contain.

Another stakeholder expressed concern that the Rationale would be lost once the standard is approved. The CISDT notes that the Rational for each requirement will be contained in the Guidelines and Technical Basis section of the standard for future reference.

One stakeholder believes that there is a conflict with the NERC defined terms "Request for Interchange" and "Interchange" as used in Requirement R3 because RFI includes intra-BA transfers. The CISDT notes R3 is consistent with BA to BA transfers that are the intent of the requirement. Intra-BA transfers are not addressed in this requirement as they are not included in the ACE equation.

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co, of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

10. Mark Kenny	Northeast Utilities	NPCC	1
11. Christina Koncz	PSEG Power LLC	NPCC	5
12. Helen Lainis	Independent Electricity System Operator	NPCC	2
13. Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14. Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15. Bruce Metruck	New York Power Authority	NPCC	6
16. Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
17. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18. Robert Pellegrini	The United Illuminating Company	NPCC	1
19. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20. David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
21. Brian Robinson	Utility Services	NPCC	8
22. Ayesha Sabouba	Hydro One Networks Inc,	NPCC	1
23. Brian Shanahan	National Grid	NPCC	1
24. Wayne Sipperly	New York Power Authority	NPCC	5
25. Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
26. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Randi Heise	Dominion NERC Compliance Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Connie Lowe	Dominion	RFC	5, 6
2.	Mike Garton	Dominion	NPCC	5, 6
3.	Louis Slade	Dominion	SERC	5, 6
4.	Michael Crowley	Dominion	SERC	1, 3
5.	Randi Heise	Dominion	MRO	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Pamela Hunter	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				

No Additional Responses

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	Louisville Gas and Electric Company and Kentucky Utilities Company	SERC	3
2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Montana, LLC	WECC	5
5.		PPL Susquehanna, LLC	RFC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

				1	2	3	4	5	6	7	8	9	10
5.	Group	Donald Hargrove	Oklahoma Gas and Electric Co	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Teri Pyle	OKGE	SPP	1
2.	Leo Staples	OKGE	SPP	5
3.	Jerry Nottnagel	OKGE	SPP	6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Gerg Cecil		RFC	6

				1	2	3	4	5	6	7	8	9	10
7.	Group	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				

No Additional Responses

				1	2	3	4	5	6	7	8	9	10
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Stan Rzad	Keys Energy Services	FRCC	1
8.	Don Cuevas	Beaches Energy Services	FRCC	1
9.	Mark Schultz	Green Cove Springs	FRCC	3

9.	Group	Rene Free	SERC OC Review Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Lowman	Duke Energy	SERC	1, 3, 5, 6
2.	Terry Bilke	MISO	SERC	2
3.	Scott Homberg	TVA	SERC	1, 3, 5, 6

10.	Group	Greg Campoli	ISO/RTO Council Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ali Merimadi	CAISO	WECC	
2.	Cheryl Mosley	ERCOT	ERCOT	
3.	Ben Li	IESO	NPCC	
4.	Kathleen Goodman	ISO New England	NPCC	
5.	Terry Bilke	MISO	RFC	
6.	Charles Yeung	SPP	SPP	

11.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
2.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1									
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5									
4.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4									
5.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1									
6.	Bernard Johnson	Oglethorpe Power Corporation	SERC										
12.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				
	Additional Member	Additional Organization	Region	Segment Selection									
1.	Mary Willey	Trans Commercial System Mgmt	WECC	1									
13.	Group	Robert Rhodes	SPP Standards Review Group		X								
	Additional Member	Additional Organization	Region	Segment Selection									
1.	Allan George	Sunflower Electric Power Corporation	SPP	1									
2.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6									
3.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6									
4.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6									
5.	Shannon Mickens	Southwest Power Pool	SPP	2									
6.	James Nail	City of Independence, MO	SPP	3									
7.	Buck Reuter	Westar Energy	SPP	1, 3, 5, 6									
14.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
15.	Individual	Michael Falvo	Independent Electricity System Operator		X								
16.	Individual	Shirley Mayadewi	Manitoba Hydro	X				X	X				
17.	Individual	Paul Kerr	Shell Energy North America						X				
18.	Individual	Anthony Jablonski	ReliabilityFirst										X
19.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
20.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
21.	Individual	Chris Scanlon	Exelon	X		X	X	X	X				
22.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
23.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
24.	Individual	Tom Bowe	PJM		X								

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Agree	Supporting Comments of "Entity Name"
South Carolina Electric and Gas	Agree	SERC OC

1. **The drafting team has revised INT-004-3 in response to stakeholder comments. Do you support the proposed changes?**

Summary Consideration: Most stakeholders agreed with the revisions to INT-004-3. Several stakeholders suggested clarifying edits with which the drafting team agreed. The following revisions were made:

- Capitalized “Dynamic Transfer” throughout for consistency.
- Added a footnote to “on-time” in Requirement R1 to point to the timing tables in INT-006-4.
- Replaced “For” with “for” in Requirement R2 (Request for Interchange).
- Removed the “,” at the end of the Severe VSL for R1 and replaced it with a “.”
- Capitalized Frequency Bias, Frequency Bias Setting in the table in the Guidelines and Technical Basis section.
- Reworded two sentences in the Guidelines and Technical Basis section for clarity.

A couple of commenters suggested improvements to the Severe VSL for Requirement R3. The existing VSL reads: “The Balancing Authority did not implement or operate a Pseudo-Tie that was included in the NAESB Electric Industry Registry publication.” The language of the requirement is for the Balancing Authority to only implement or operate a Pseudo-Tie that is registered. The CISDT has revised the VSL as suggested to: “The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.”

A couple of commenters suggested the addition of the LSE as an applicable entity in addition to the PSE. The CISDT notes that having multiple entities responsible for the same requirement will lead to confusion and a reliability gap. Only one entity can be responsible for any requirement. The use of the PSE ensures that any PSE that is taking this action, even if not registered as an LSE, is still the responsible entity.

A few commenters had questions or concerns around the registration of Pseudo-Ties. Creating a formal registration process creates a clear mechanism by which all entities are informed and can account for Pseudo-Ties in congestion management procedures. Inclusion in congestion management procedures will need to be determined on a case by case basis as each Pseudo-Tie configuration is unique. While NAESB business practices are commercial in nature, the information in the EIR is a common tool used by both business practice and reliability tools. As such, the committee that supports this tool is a joint NERC and NAESB subcommittee. The registration process has yet to be detailed and it is possible that process to identify how the Pseudo-Tie is handled in congestion management procedures. If all entities do not agree on the ‘setup’ during registration, then the Pseudo-Ties would not become implemented. The CISDT encourages all entities to participate in the development of the Pseudo-Tie registration development in NAESB.

Organization	Yes or No	Question 1 Comment
PPL NERC Registered Affiliates	No	These comments are submitted on behalf of the following PPL NERC Registered Affiliates: Louisville Gas and Electric Company and Kentucky Utilities Company; PPL EnergyPlus, LLC; PPL Electric Utilities Corporation; PPL Generation, LLC, PPL Susquehanna, LLC and PPL Montana, LLC on behalf of its NERC registered entities. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. It is unclear in R1 as to which BA's congestion management procedures the information for the Psuedo-Tie is to be included, the Source BA's or the Sink BA's (or both).
Oklahoma Gas and Electric Co	No	INT-004-3 R3 requires BA's to only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry. This is clearly a Commercial/Business practice issue. From a reliability perspective if the RC, PC and TSP are informed, a BA should be able to implement or operate a Pseudo-Tie. Requiring administrative reporting to a non-reliability (commercial / business practice) entity is not appropriate for the Reliability Standards. This requirement falls clearly with Criteria A and Criteria B6 of the paragraph 81 criteria and should be removed from the draft Standard. Criterion A (Overarching Criterion) The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES. Criteria B (Identifying Criteria)B6. Commercial or Business Practice The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues. This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	Duke Energy suggests the following change to R3 of INT-004-3,"Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. "Since NAESB will define the requirements for Pseudo-Tie registration, there is no need to add "in support of congestion management procedures." Based on the Purpose of the standard, as written, our interpretation is that this is already understood.
ACES Standards Collaborators	No	(1) We do not support this concept as a reliability standard and believe it should be retired and transferred to NAESB. The purpose statement of the standard is to ensure that Dynamic Schedules and Pseudo Ties are "accounted for appropriately in congestion management procedures." While this is an important business practice to ensure the schedules are treated equitably, it is not a reliability issue and should not be in a NERC standard. Congestion management procedures are designed and intended to ensure the transmission service is curtailed based on its priority so that lower priority service does not supersede higher priority service. It designed to comport with FERC pro forma tariff requirements for the treatment of various levels of transmission service. A reliability entity such as a BA, TOP, or RC must still be able to reduce loading via other methods (e.g. manual redispatch or transmission reconfiguration) in addition to congestion management. While some entities (e.g. ISO and RTOs) have designed very effective congestion management procedures that are defined by their tariffs through the use of locational marginal pricing (LMP), they are still required to have other capabilities to reduce loading (e.g. manual redispatch or transmission configuration). Thus, congestion management is clearly a business practice designed to facilitate the orderly curtailment of transmission service so that lower priority service is curtailed first. Congestion management is a tool to facilitate management of transmission service curtailments. It is not a reliability tool. Thus, a NERC

Organization	Yes or No	Question 1 Comment
		standard designed to ensure that Dynamic Schedules and Pseudo-Ties are tagged is an important business practice but is not required for reliability. This standard should be retired and moved to NAESB.
Cowlitz PUD	No	Cowlitz disagrees with the SDT dismissal of comments submitted by Seattle City Light.
Manitoba Hydro	No	(1) R1 - We note the addition of language by the SDT in the Rationale for R1 with respect to a situation where no forecast may be available. It is Manitoba Hydro's view that the text currently contained in the Rationale with respect to what is required to be in an RFI belongs more appropriately in the body of the standard itself rather than in a Rationale. Our understanding is that the content of the Rationale text boxes will be moved to the Application Guidelines section of the standard upon approval of the standard; the content of the Application Guidelines section is not one of the mandatory or enforceable components of a reliability standard even though they may be looked to for guidance by entities and auditors. This particular Rationale goes beyond an explanation by the SDT of why the requirement/part is required, or why the wording changes are appropriate, and provide specific direction as to the appropriate inclusion in the RFI; something that is missing in the body of the standard itself. (Law, Export Operations, RCD)(2) R1 - The additional language added by the SDT, while it does attempt to address circumstances where no forecast is available, still leaves some uncertainty as to the appropriate volume to be tagged in an RFI. Suggested alternative language to make it abundantly clear would be:"If no forecast is available for the Dynamic Schedule, the energy profile in the Request for Interchange should be the expected maximum value of the Dynamic Schedule."
Shell Energy North America	No	Shell Energy North America disagrees with the comments filed and the decision to revert the applicability of INT-004 to Purchasing Selling Entities.

Organization	Yes or No	Question 1 Comment
		The wording in the proposal at R1 retains the condition existing in the currently approved INT-001 standard that the subject transactions are taking place to serve load. R2 is entirely contingent on R1 and continues the misplaced applicability to PSEs. This load serving aspect remains the impetus to the belief by some stakeholders that this type of activity has reliability impacts, rather than being the business process requirements that they truly are. If the R1 and R2 requirements of the standard are to be maintained, the applicability should be on Load Serving Entities as originally proposed in the this Project. LSEs engaging in such transactions are the responsible party, and if the LSE is not also a PSE, a reliability gap will be created by setting the applicability to PSEs.
ReliabilityFirst	No	During the last comment period, ReliabilityFirst questioned the term “on-time” within Requirement R1. ReliabilityFirst appreciates the SDT response that “The term ‘onâ€time’ is addressed in the timing tables contained in INTâ€006”. ReliabilityFirst believes a reference to the INT-006 standard should be placed in the INT-004-3 standard. Absent a reference to the INT-006 standard, those not familiar with the table in the INT-006 standard may not understand the meaning of the term “on-time” and thus cause both reliability and compliance complications.
Xcel Energy	No	Xcel Energy is voting negative b/c we do not agree with the inclusion of Pseudo-Ties. Here are our specific issues with each requirement:R1-Pseudo-Ties do not have tags, they are metered into the BA as part of the NAI term of the ACE equation.R2- All references to Pseudo-Ties should be removed. This requirement is just for “Confirmed Interchange” that is a Dynamic Schedule, which is part of the NSI term of the ACE equation.R3-This requirement should specify a minimum level before registration of a Pseudo-Tie is required. We feel Pseudo-Ties should only be registered if they are in a congested transmission area.

Organization	Yes or No	Question 1 Comment
Cowlitz PUD	No	The Standard mixes applicability in the Requirement. Please state applicability in Section 4.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	INT-004-3 R1: How do entities know the forecast for submitted pseudo-ties included in congestion management? In order to add bounds to the alternate method, we request that the SDT consider adding the following (bolded section) to R1:Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method that provides a projection of usage of the Pseudo-Tie to the Transmission Operator.INT-004-3 R3: We request that the SDT consider adding the following (bolded section) to R3 in order to clarify roles and responsibilities:Each Purchase-Selling Entity is responsible for registering Pseudo-Ties in the NAESB Electronic Industry Registry publication. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures.
SERC OC Review Group	Yes	We respectfully submit a change to R3 Sever VSL to further align with R3.Current Language: The Balancing Authority did not implement or operate a Pseudo-Tie that was included in the NAESB Electric Industry Registry publication.Proposed Language: The Balancing Authority DELETE: “did not” implement Add: “ed” or operate Add: “d”a Pseudo-Tie that was Add: “Not” included in the NAESB Electric Industry Registry publication.
Bonneville Power Administration	Yes	BPA supports the proposed changes to the draft INT-004-3 except for the Rational in R1. The Rationale starting with the second sentence is not valid

Organization	Yes or No	Question 1 Comment
		for R1. R1 is regarding when a PSE must submit an RFI for Dynamic Transfer. How information is utilized does not belong in a rationale for such a requirement. The second and third sentence in Rational R1 should be removed. The second sentence is unclear as to what is meant by "max transaction profile". E-tags do not have a "transaction profile". The third sentence in the rationale implies that if a forecast is used, the transmission profile can be exceeded. In the Table of Compliance Elements, the last sentence of the Severe VSL description for R1 ends with a comma. Assuming more verbiage does not follow the comma but is not visible in the table, the comma should be replaced with a period. Dynamic Transfer is a defined NERC Glossary term and as such, BPA suggests that the draft team capitalize the term if its use is intended to align with the NERC definition.
SPP Standards Review Group	Yes	While we have no issues with the proposed changes to the most recent draft that has been posted, in this reading we did note a few items that we missed in previous readings of the standard. Most of these items are minor with the exception of an item regarding the Severe VSL for R3. This is a significant item and needs to be corrected in the proposed draft in order for us to continue to support the proposed standard. We recommend modifying the Severe VSL for R3 to read: 'The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.' This wording is more on-point since the requirement does not require Balancing Authorities to implement or operate all Pseudo-Ties in the NAESB Registry but restricts the Balancing Authority to only implement or operate those Pseudo-Ties which are included in the Registry. Capitalize Dynamic Transfer throughout the Background and the Application Guidelines sections since the term is in the Glossary of Terms. Use a lower case 'for' in 'Request for Interchange' in R2.Capitalize Frequency Bias Setting, Frequency Bias and Dynamic Schedule in the table in the Application Guidelines on Page 9.We suggest modifying the first sentence under the General Considerations for Curtailments of

Organization	Yes or No	Question 1 Comment
		Dynamic Transfers section in the Application Guidelines to read: 'The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.'Capitalize 'Curtailment' in the paragraph under For Dynamic Schedules in the Application Guidelines.We suggest modifying the last paragraph on Page 9 of the Application Guidelines to read: 'Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.'Use a lower case 'signal' in Dynamic Transfer signal in the last paragraph of the Application Guidelines on Page 10.
American Electric Power	Yes	Though we welcome the addition of the PSE in the applicability section, we believe the LSE should be retained rather than replacing it entirely. In some non-RTO areas for example, there is the potential that it is the LSE who would be tasked with performing this work.Our negative vote on this standard is solely driven by the removal of the LSE in the Applicability section. We believe that the BA, PSE, *and* LSE should all be included.
Exelon	Yes	We support the combination of INT-001 and INT-003 however, the registration of a Pseudo - Tie in NAESB must be transparent to all parties. Currently, that information is not readily available.
Florida Municipal Power Agency		Our comments from last November's posting were not addressed. In summary, FMPA believes these standards are not important for reliability, are commercial in nature, and are duplicative of NAESB standards and BAL standards. Please refer to our comments submitted on November 13, 2013.
PJM	No	PJM does not support R1, as written. A requirement to tag Pseudo-Ties ensures that all involved parties, including wide-area congestion management tools, have visibility into the path and estimated magnitude of the transfer; however, the alternative to include the Pseudo Tie in

Organization	Yes or No	Question 1 Comment
		"congestion management procedures via an alternate method" fails to provide that same visibility. The existing language implies that a local congestion management procedure established in the Native BA's footprint is sufficient to meet the requirement for not tagging a Pseudo Tie that may span several Intermediate BAs. If the requirement is meant to ensure that all involved BAs and all congestion management procedures/tools benefit from added visibility, the existing language is insufficient. PJM also asks the drafting team to consider extending R3 to require that a Balancing Authority only implement and operate Dynamic Schedules that have been registered in the NAESB Electric Industry Registry. If the drafting team sees value in requiring the registration of Pseudo Ties, whether or not they are tagged, PJM believes similar value could be gained by extending the requirement to Dynamic Schedules.
Northeast Power Coordinating Council	Yes	
Dominion NERC Compliance Policy	Yes	
Arizona Public Service Company	Yes	
ISO/RTO Council Standards Review Committee	Yes	
Independent Electricity System Operator	Yes	

2. The drafting team has the definition of Request for Interchange (RFI) in response to stakeholder comments. Do you support the proposed changes?

Summary Consideration: The majority of commenters agreed with the proposed revisions to the definition of Request for Interchange (RFI).

One commenter suggested that the proposed defined term Arranged Interchange is not needed as it is effectively the same as (and redundant to) Request for Interchange. The CISDT disagrees that the two terms are redundant. An RFI is a collection of data whereas Arranged Interchange is a state where the RFI has been submitted. These definitions align with NAESB Business practices definitions and the NERC Interchange Reference Guidelines, version 2.

Another commenter noted that the definition of Request for Interchange references the NAESB Business Practice Standards and they are not publicly available. The CISDT notes that NAESB business practices are available to the public and there is a cost associated with these. FERC has ruled in the past that this is a reasonable practice.

One stakeholder disagreed with the inclusion of intra-BA schedules in the definition because there is a direct conflict with other NERC glossary terms. The CISDT does not believe that there is a conflict with other terms and notes that this was added to the definition to address a FERC Order 693 directive.

Organization	Yes or No	Question 2 Comment
PPL NERC Registered Affiliates	No	The proposed defined term Arranged Interchange is not needed as it is effectively the same as (and redundant to) Request for Interchange. Each is a set of data that has been submitted for approval. The verb “submitted” implies “submitted for approval” in the definition of Request for Interchange. To clarify this issue, the SDT should revise the definition of Request for Interchange to the following: A collection of data as defined in the NAESB Business Practice Standards, that has been initiated or revised and submitted for approval to the Sink Balancing Authority for the purpose of implementing bilateral Interchange between Source and Sink Balancing Authorities or an energy transfer within a single Balancing Authority.

Organization	Yes or No	Question 2 Comment
Oklahoma Gas and Electric Co	No	The definition of "Request for Interchange," references the NAESB Business Practice Standards. I cannot submit an affirmative vote because I do not have access to the NAESB Business Practice Standards; I have no idea what constitutes the data defined therein. As long as the NAESB standards are not open and freely available like the NERC Standards, I cannot in good conscience vote affirmative on a NERC Reliability Standard or NERC Glossary Definition that references them.
ACES Standards Collaborators	No	(1) We disagree with the inclusion of intra-BA schedules because there is a direct conflict with other NERC glossary terms. "Interchange" is defined in the NERC glossary as "Energy transfers that cross Balancing Authority boundaries." Thus, "Interchange" only deals with external transfers and does not include intra-BA schedules. We think it will be confusing to define a "Request for Interchange" inconsistently with "Interchange" and that they will be used inconsistently as documented in our response to question 4 regarding INT-010-2 R3. "Request for Interchange" should literally be a request to schedule the NERC term "Interchange," which would be for energy transfers that cross BA boundaries. The proposed definition of "Request for Interchange" conflicts with the existing definition of "Interchange"and needs to be modified so they are both aligned.
Bonneville Power Administration	Yes	BPA supports the proposed changes to the Request for Interchange definition.
Florida Municipal Power Agency		Please see FMPA comments to Question 1.
Dominion NERC Compliance Policy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company;	Yes	

Organization	Yes or No	Question 2 Comment
Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
Duke Energy	Yes	
Arizona Public Service Company	Yes	
SERC OC Review Group	Yes	
ISO/RTO Council Standards Review Committee	Yes	
SPP Standards Review Group	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
American Electric Power	Yes	
Cowlitz PUD	Yes	
PJM	Yes	

3. The drafting team has revised the definition of Arranged Interchange in response to stakeholder comments. Do you support the proposed changes?

Summary Consideration: The majority of commenters agreed with the proposed revisions to the definition of Arranged Interchange.

One commenter was unclear how the proposed change in the definition of Arranged Interchange would impact other standards, particularly MOD-004-1, R11 and R12. The revisions to this defined term do not change the intent of the requirements or defined terms in which it is used. The revisions provide additional clarity for these requirements and defined terms.

One commenter disagreed with the inclusion of the clause “initial or revised”. The CISDT notes that this is included in the existing, approved definition because Arranged Interchange may be revised and the team believes that this clarification is an improvement to the definition.

Organization	Yes or No	Question 3 Comment
PPL NERC Registered Affiliates		No.See comment to question 2. It is unclear how the proposed change in the definition of Arranged Interchange would impact other standards, particularly MOD-004-1 R11 and R12. Therefore, remove the proposed changes to this definition from the project and use only the one term - Request for Interchange.
Duke Energy		Yes. Duke Energy supports the changes made by the SDT.
Florida Municipal Power Agency		Please see FMPA comments to Question 1.
ACES Standards Collaborators		We disagree with the inclusion of the clause “initial or revised.” Does the definition of “Request for Interchange” include initial requests and revisions to those requests? If so, then the inclusion of the clause “initial or revised” is superfluous. If not, then the definition for Arranged Interchange is implying that “Request for Interchange” can include revisions incorrectly. Either way, the clause should be removed.
Bonneville Power		BPA supports the proposed changes to the Arranged Interchange definition.

Organization	Yes or No	Question 3 Comment
Administration		
Northeast Power Coordinating Council		Yes.
Dominion NERC Compliance Policy		Yes.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		Yes.
Oklahoma Gas and Electric Co		Yes.
Arizona Public Service Company		Yes
SERC OC Review Group		Yes
ISO/RTO Council Standards Review Committee		Yes
SPP Standards Review Group		Yes

Organization	Yes or No	Question 3 Comment
Manitoba Hydro		Yes
American Electric Power		Yes.
PJM	Yes	
Cowlitz PUD		Yes

4. The drafting team has revised INT-010-2 in response to stakeholder comments. Do you support the proposed changes?

Summary Consideration: Many stakeholders agreed with the revisions to INT-010-2. Several stakeholders suggested clarifying edits with which the drafting team agreed. The following revisions were made:

- Added the Guidelines and Technical Basis Section to the clean version of the standard (it was in the redline version but inadvertently omitted here).
- Revised "RFI" to "Request for Interchange" for consistency throughout.
- Added "when the use of the energy sharing agreement exceeded 60 minutes." To the VSLs for R1 to clarify that an RFI does not need to be submitted unless this condition is met. This matches the language of the requirement.
- Capitalized "Dynamic Transfer" throughout for consistency.
- Reworded two sentences in the Guidelines and Technical Basis section for clarity.
- Removed Transmission Service Provider from section 1.2, Evidence Retention.
- Added "(CEA)" after "Compliance Enforcement Authority" in section 1.2, Evidence Retention.
- Capitalized "Schedule" in the term "Interchange Schedule".

Two stakeholders questioned the use of the phrase "or other reliability needs" within Requirement R1. As this requirement relates to energy sharing agreements, the CISDT believes that the content of those agreements will address the "other reliability needs" and that the drafting team is unable to develop a comprehensive list of what those agreements might contain.

Another stakeholder expressed concern that the Rationale would be lost once the standard is approved. The CISDT notes that the Rational for each requirement will be contained in the Guidelines and Technical Basis section of the standard for future reference.

One stakeholder believes that there is a conflict with the NERC defined terms "Request for Interchange" and "Interchange" as used in Requirement R3 because RFI includes intra-BA transfers. The CISDT notes R3 is consistent with BA to BA transfers that are the intent of the requirement. Intra-BA transfers are not addressed in this requirement as they are not included in the ACE equation.

Organization	Yes or No	Question 4 Comment
ACES Standards Collaborators		(1) "Request for Interchange" is used inconsistently with "Interchange" in R3. Request for Interchange includes intra-BA transfers. However, by definition, Interchange does not since it only includes "energy transfers that cross Balancing Authority boundaries." Thus, the requirement is written incorrectly when the Request for Interchange is for an intra-BA energy transfers. As an example, R3 requires that a Request for Interchange should be submitted within 60 minutes of the "start of the scheduled Interchange." If the Request for Interchange is for an intra-BA energy transfer, to which Interchange schedule does the requirement refer ? It cannot refer to the Interchange schedule associated with the Request for Interchange, because the definition Interchange does not include intra-BA schedules. The conflict of the NERC defined terms "Request for Interchange" and "Interchange" has created ambiguity and uncertainty in the requirements and needs to be resolved.(2) Thank you for the opportunity to comment.
Cowlitz PUD		Abstain
Manitoba Hydro		Although Manitoba Hydro supports the proposed changes, we have the following comments: (1) R1 - unclear what the phrase 'other reliability needs' is meant to cover. The remainder of the standard only talks about resource loss and doesn't address 'other reliability needs'. (2) M1 - should include greater detail from requirement language. i.e. "The Balancing Authority that uses its energy sharing agreement where the duration of use exceeds 60 minutes from the resource loss shall have...."(3) M3 - RFI is used here, whereas Request for Interchange is used elsewhere. If the RFI acronym is desired, Request for Interchange should be defined as such at its first use and RFI used consistently throughout.(4) VSLs, R1 - RFI is used here, whereas Request for Interchange is used elsewhere. If the RFI acronym is desired, Request for Interchange should be defined as such at its first use and RFI used consistently throughout.(5) VSLs, R2 - RFI is used here, whereas Request for Interchange is used elsewhere. If the RFI acronym is desired, Request for Interchange

Organization	Yes or No	Question 4 Comment
		should be defined as such at its first use and RFI used consistently throughout. Also, the words ‘reflecting an Interchange Schedule’ should be inserted following ‘Request for Interchange’. ‘The’ scheduled interchange should be ‘that’ scheduled interchange.
Bonneville Power Administration		BPA supports the proposed changes to the draft INT-010-2 with the following comment:Dynamic Transfer is a defined NERC Glossary term and as such, BPA suggests that the draft team capitalize the term if its use is intended to align with the NERC definition.
Cowlitz PUD		Cowlitz disagrees with the SDT's dismissal of comments submitted by Seattle City Light and NextEra.
ReliabilityFirst		During the last comment period, ReliabilityFirst requested clarification of the term “energy sharing agreement” within Requirement R1. ReliabilityFirst appreciates the SDT response (and updated rationale box within the standard) that stated “There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.” ReliabilityFirst does have a concern that once the standard is approved, the rational box will be removed from the standard and the clarification of this term may be lost. ReliabilityFirst recommends including a portion of the rational into the requirement as follows: “The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement [(regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled)] or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted...”
Florida Municipal Power		Please see FMPA comments to Question 1.

Organization	Yes or No	Question 4 Comment
Agency		
Independent Electricity System Operator		The revised R1 is unclear on the condition under which a BA needs to submit an RFI no more than 60 minutes beyond the resource loss. The phrase "or other reliability needs" R1 seems to be out of place and subject to a number of possible interpretations. R1 stipulates that:R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. We ask the SDT to revise this to more clearly convey the intent.
SERC OC Review Group		Yes. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Duke Energy		Yes. Duke Energy supports the changes made by the SDT.
SPP Standards Review Group		YesWhile we have no issues with the proposed changes to the most recent draft that has been posted, in this reading we did note a few items that we missed in previous readings of the standard. Most of these items are minor with the exception of items in the Severe VSL for R1 and in the Compliance 1.2 Evidence Retention section. These are significant items and need to be corrected in the proposed draft in order for us to maintain our support for the proposed standard.RFIs are only required when an energy sharing agreement is used for more than 60 minutes. The latter portion of the Severe VSL for R1 (after the OR) is currently written such that a Balancing Authority would be non-compliant if it failed to submit a RFI regardless of the length of time the energy sharing agreement was utilized. We recommend inserting '...when the use of the energy sharing agreement exceeded 60 minutes...' at the end of the VSL.Delete

Organization	Yes or No	Question 4 Comment
		'...and Transmission Service provider...' from the Compliance 1.2 Evidence Retention section. The Balancing Authority is the only applicable entity listed in the standard. In that same sentence, insert '(CEA)' following Compliance Enforcement Authority since CEA is used later in this section.Capitalize 'schedule' in Interchange Schedule in R3 and M3. It is a defined term in the Glossary of Terms.The Application Guidelines were not included in the clean version of the standard.Capitalize Dynamic Transfer throughout the Application Guidelines section since it is a defined term in the Glossary of Terms.Modify the first sentence in the Application Guidelines such that it reads the same as we suggested in INT-004-3. 'The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.'Also as in INT-004-3, we suggest modifying the next to last paragraph in the Application Guidelines to read: 'Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.'
Arizona Public Service Company		Yes
ISO/RTO Council Standards Review Committee		Yes
Northeast Power Coordinating Council		Yes.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation;		Yes.

Organization	Yes or No	Question 4 Comment
Southern Company Generation and Energy Marketing		
PPL NERC Registered Affiliates		Yes.
PJM	Yes	
Oklahoma Gas and Electric Co		Yes.

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

Description of Current Draft

This is the third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	September – October 2013
Recirculation ballot	December 2013
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1.0	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2.0	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3.0	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3.0	July 1, 2010	Approved by FERC	Revised
4.0	TBD	Adopted by the NERC Board Of Trustees	Revised in Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Evaluation of Interchange Transactions**
2. **Number:** INT-006-4
3. **Purpose:** To ensure that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Transmission Service Provider
5. **Background:**

This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-006-4 continues to be the reliability assessment of Interchange Transactions prior to their implementation.

The content of INT-006-4 has been revised and expanded in the following manner:

- R1 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Balancing Authority must deny the transition.
- R2 was created by revising R1 from INT-006-3. This requirement ensures that Transmission Service Providers involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Transmission Service Provider must deny the transition.
- R3 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange.
- R4 was created by moving and revising R1 from INT-007-1, which has been retired as part of the project. This requirement lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange.
- R5 was created by moving and revising R1 from INT-008-3, which has been retired as part of the project. This requirement lists the entities to which a Sink Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.
- Attachment 1 timing tables for WECC were modified to address scheduling on a 15 minute basis.

Requirements and Measures

R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

> Rationale for R1: Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

M1. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R1)

> Rationale for R2: TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in Requirement R1, Part 2.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

R2. Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M2. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each Arranged Interchange or emergency Arranged Interchange within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R2)

R3. The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

3.1. If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.

M3. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request and, if applicable, communicated denial to the Reliability Coordinator no more than 10 minutes after the denial. (R3)

R4. Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

- It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

M4. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that, under the conditions in R4, it did not transition an Arranged Interchange to Confirmed Interchange. (R4)

R5. For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

5.1. The Source Balancing Authority,

5.2. Each Intermediate Balancing Authority,

5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,

5.4. Each Transmission Service Provider included in the Arranged Interchange, and

5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

M5. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it notified the entities of the on-time Confirmed Interchange such that the notification was delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D. (R5)

B. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R3, R4, and R5 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R2 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange. OR The Scheduling Path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.
R2	Operations Planning,	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Same-day Operations, Real-time Operations					Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
R3	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
R4	Operations Planning, Same-day Operations,	Lower	N/A	N/A	N/A	The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-time Operations					an Arranged Interchange to Confirmed Interchange.
R5	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Sink Balancing Authority did not notify all of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.	The Sink Balancing Authority did not notify any of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange. OR The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify one or more of the entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Attachment 1 – Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [1] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[2]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[2]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time		≤ 20 minutes from Arranged Interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start

[1] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[2] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

[redacted]

Attachment 1 – Timing Tables

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<10 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is not the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 5 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of	On-time		≤ 6 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[4] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
the hour					
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		$\leq$ 7 minutes from Arranged Interchange receipt		$\geq$ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		$\leq$ 8 minutes from Arranged Interchange receipt		$\geq$ 3 minutes prior to ramp start
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		$\leq$ 9 minutes from Arranged Interchange receipt		$\geq$ 3 minutes prior to ramp start
<1 hour and $\geq$ 15 minutes prior to ramp start	On-time		$\leq$ 10 minutes from Arranged Interchange receipt		$\geq$ 3 minutes prior to ramp start
$\geq$ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged interchange receipt		$\geq$ 39 minutes prior to ramp start
$\geq$ 4 hours prior to ramp start	On-time		$\leq$ 2 hours from Arranged Interchange receipt		$\geq$ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time $\geq$ 00:00 PPT of following day	On-time		By 12:00 PPT of day the Arranged Interchange was received		$\geq$ 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing Interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - All reliability entities involved in the Arranged Interchange are valid.
    - Generation source and Load sink are defined.
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
    - Distribute notification as each entity approves or denies an Arranged Interchange.
    - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
    - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

- Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
  - Receive distribution of Arranged Interchange
  - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
  - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
  - Submit a request to modify Interchange

- While Interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
  - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
  - How to notify others that it is activating the plan
  - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
  - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
  - Delegation of approval rights and proxy actions, if such approaches will be used.
  - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
  - Personnel plans for short-term and extended periods.
  - Training of personnel in the use of the plan.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
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This is the third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	September – October 2013
Recirculation ballot	December 2013
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1.0	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2.0	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3.0	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3.0	July 1, 2010	Approved by FERC	Revised
4.0	TBD	Adopted by the NERC Board Of Trustees	Revised in Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Evaluation of Interchange Transactions**
2. **Number:** INT-006-4
3. **Purpose:** To ensure that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Transmission Service Provider
5. **Background:**

This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-006-4 continues to be the reliability assessment of Interchange Transactions prior to their implementation.

The content of INT-006-4 has been revised and expanded in the following manner:

- R1 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Balancing Authority must deny the transition.
- R2 was created by revising R1 from INT-006-3. This requirement ensures that Transmission Service Providers involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Transmission Service Provider must deny the transition.
- R3 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange.
- R4 was created by moving and revising R1 from INT-007-1, which has been retired as part of the project. This requirement lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange.
- R5 was created by moving and revising R1 from INT-008-3, which has been retired as part of the project. This requirement lists the entities to which a Sink Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.
- Attachment 1 timing tables for WECC were modified to address scheduling on a 15 minute basis.

Requirements and Measures

Rationale for R1: Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the ~~s~~Scheduling ~~p~~Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

M1. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R1)

Rationale for R2: TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in Requirement R1, Part 2.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

R2. Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M2. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each Arranged Interchange or emergency Arranged Interchange ~~request for its approval to transition an Arranged Interchange to a Confirmed Interchange~~ within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R2)

R3. The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

3.1. If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.

M3. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request and, if applicable, ~~or that it~~ communicated denial to the Reliability Coordinator no more than 10 minutes after the denial. (R3)

R4. Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

- It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

M4. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that, under the conditions in R4, it did not transition an Arranged Interchange to Confirmed Interchange. (R4)

R5. For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

5.1. The Source Balancing Authority,

5.2. Each Intermediate Balancing Authority,

5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,

5.4. Each Transmission Service Provider included in the Arranged Interchange, and

5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

M5. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it notified the entities of the on-time Confirmed Interchange such that the notification ~~is~~ was delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D. (R5)

B. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, ~~R2~~R3, R4, and R5 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with ~~R3~~ R2 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it~~s transition to Confirmed Interchange~~ prior to the expiration of the time period defined in Attachment 1, Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange. OR The ~~s~~Scheduling ~~p~~Path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it~~s transition to Confirmed Interchange~~ prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
R3	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning an Arranged Interchange to Confirmed Interchange.
R5	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Sink Balancing Authority did not notify all of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.	The Sink Balancing Authority did not notify any of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange. OR The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify one or more of the entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Attachment 1 – Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [1] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[2]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[52]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time		≤ 20 minutes from Arranged Interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start

[1] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[2] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

[redacted]Attachment 1 – Timing Tables

[redacted]

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]~~[7]~~**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<10 minutes prior to ramp start and <u><</u>1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		<u><</u> 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and <u><</u>1 hour after transaction start time where transaction start time is not the top of the hour	Late		Entities have up to 10 minutes to respond.		<u><</u> 3 minutes after receipt of Confirmed Interchange
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		<u><</u> 5 minutes from Arranged Interchange receipt		<u>></u> 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of	On-time		<u><</u> 6 minutes from Arranged Interchange receipt		<u>></u> 3 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[4] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]~~7~~**	**BA Prepares Confirmed Interchange for Implementation**
the hour					
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		$\le$ 7 minutes from Arranged Interchange receipt		$\ge$ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		$\le$ 8 minutes from Arranged Interchange receipt		$\ge$ 3 minutes prior to ramp start
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		$\le$ 9 minutes from Arranged Interchange receipt		$\ge$ 3 minutes prior to ramp start
<1 hour and $\ge$ 15 minutes prior to ramp start	On-time		$\le$ 10 minutes from Arranged Interchange receipt		$\ge$ 3 minutes prior to ramp start
$\ge$ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged interchange receipt		$\ge$ 39 minutes prior to ramp start
$\ge$ 4 hours prior to ramp start	On-time		$\le$ 2 hours from Arranged Interchange receipt		$\ge$ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time $\ge$ 00:00 PPT of following day	On-time		By 12:00 PPT of day the Arranged Interchange was received		$\ge$ 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing ~~i~~Interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - All reliability entities involved in the Arranged Interchange are valid.
    - Generation source and ~~l~~Load sink are defined.
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
    - Distribute notification as each entity approves or denies an Arranged Interchange.
    - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
    - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

- Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
  - Receive distribution of Arranged Interchange
  - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
  - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
  - Submit a request to modify Interchange

- While ~~i~~Interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
  - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
  - How to notify others that it is activating the plan
  - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
  - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
  - Delegation of approval rights and proxy actions, if such approaches will be used.
  - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
  - Personnel plans for short-term and extended periods.
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Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Implementation of Interchange**

2. **Number:** **INT-009-2**

3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.

4. **Applicability:**

   4.1. Balancing Authority.

5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.

   The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term "Composite Confirmed Interchange" has been introduced.

   The content of INT-009-2 has been revised and expanded in the following manner:

   - R1 was combined with INT-003-3 R1 and modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.
   - R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Net Interchange Actual term for their ACE controls.
   - R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls a high-voltage direct current tie coordinates the Confirmed Interchange.

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual (NI_A) term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

Rationale for R2: R12.3 of BAL-005-2b addresses common metering for Dynamic Schedules and Pseudo-Ties but not their implementation into ACE. Requirement R2 is parallel to R10 of BAL-005-2b which only addresses Dynamic Schedules. Presently, there is a gap in the BAL standards that this requirement fills for Pseudo-Ties.

M2. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process). (R2)

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2 and R3 for the most recent 3 months plus the current month.

If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange.
R2	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual (NI_A) term of their respective control ACE (or alternate control process).
R3	Real-time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

Description of Current Draft

This is the third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	September – October 2013
Recirculation ballot	December2013
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Implementation of Interchange**
2. **Number:** **INT-009-2**
3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process~~ and maintain the generation-to-load balance~~.
4. **Applicability:**

   4.1. Balancing Authority.

5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.

   The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term "Composite Confirmed Interchange" has been introduced.

   The content of INT-009-2 has been revised and expanded in the following manner:

   - R1 was combined with INT-003-3 R1 and modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.
   - R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Net Interchange Actual term for their ACE controls.
   - R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls a high-voltage direct current tie coordinates the Confirmed Interchange.

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any ~~i~~Interchange ~~as directed by a Reliability Coordinator ~~per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-~~-~~t~~T~~ime Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any ~~i~~Interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual (NI_A) term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real-~~-~~t~~T~~ime Operations*]

M2. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process). (R2)

> Rationale for R2: R12.3 of BAL-005-2b addresses common metering for Dynamic Schedules and Pseudo-Ties but not their implementation into ACE. Requirement R2 is parallel~~equivalent~~ to R10 of BAL-005-2b which only addresses Dynamic Schedules. Presently, there is a gap in the BAL standards that this requirement fills for Pseudo-Ties.

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie~~ if applicable~~. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-~~-~~t~~T~~ime Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2 and R3 for the most recent 3 months plus the current month.

If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Real-~~T~~time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any ~~i~~Interchange ~~as directed by a Reliability Coordinator~~ per INT-010-2 not yet captured in the Composite Confirmed Interchange~~, for that hour~~.
R2	Real-t~~T~~ime Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual (NI_A) term of their respective control ACE (or alternate control process).
R3	Real-~~T~~time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current

						tie.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
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6. Project became inactive until February, 2013.
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Description of Current Draft

This is the third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	September - October 2013
Recirculation ballot	December 2013
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Adopted by the NERC Board of Trustees	New standard developed

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Intra-Balancing Authority Transaction Identification**

2. **Number:** **INT-011-1**

3. **Purpose:** To ensure that transfers within a Balancing Authority Area using Point to Point Transmission Service are communicated and accounted for in congestion management procedures.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Load-Serving Entities

5. **Background:**

   This standard was created in response to a FERC directive in Order 693, paragraph 817: *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

   The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

B. Requirements and Measures

R1. Each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange unless the information about intra-Balancing Authority transfers is included in congestion management procedure(s) via an alternate method. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations]*

M1. Each Load-Serving Entity subject to R1 shall have evidence, such as dated and time-stamped electronic records, documentation of congestion management procedures, or other similar evidence, that a Request for Interchange was submitted for each Point to Point Transmission Service intra-Balancing Authority transfer subject to R1 or that each intra-Balancing Authority transfer subject to R1 was accounted for in congestion management procedure(s) via an alternate method. (R1)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Load-Serving Entity shall keep data or evidence to show compliance with R1 for the most recent three months plus the current month unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	*Operations Planning, Same-day Operations*	*Lower*	N/A	N/A	N/A	The Load-Serving Entity used Point to Point Transmission Service for an intra-Balancing Authority Area transfer, and did not submit a Request for Interchange for an intra-Balancing Authority transfer that is not included in congestion management procedure(s) via an alternate method.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

NERC

Proposed Definitions for the NERC Glossary of Terms

Project 2008-12: Coordinate Interchange Standards

The Coordinate Interchange Standards Drafting (CISDT) received comments on the proposed set of definitions to be revised or added to the NERC Glossary of Terms. The CISDT made minor clarifying edits of several of the definitions based on these comments. These proposed defined terms are being posted for a final ballot.

Revisions to Defined Terms in the NERC Glossary

- **Dynamic Interchange Schedule or Dynamic Schedule:** A time-varying energy transfer that is updated in Real-time and included in the Net Interchange Schedule term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Pseudo-Tie:** A time-varying energy transfer that is updated in Real-time and included in the Net Interchange Actual term (NI_A) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Confirmed Interchange** - The state where no party has denied and all required parties have approved the Arranged Interchange.
- **Adjacent Balancing Authority** - A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
- **Intermediate Balancing Authority** - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
- **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.
- **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.
- **Operational Planning Analysis:** An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Proposed additional Defined Terms to be added to the NERC Glossary

- **Reliability Adjustment Arranged Interchange** – A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
- **Composite Confirmed Interchange –** The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
- **Attaining Balancing Authority:** A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.
- **Native Balancing Area:** A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

Proposed Definitions for the NERC Glossary of Terms

Project 2008-12: Coordinate Interchange Standards

The Coordinate Interchange Standards Drafting (CISDT) received comments on the proposed set of definitions to be revised or added to the NERC Glossary of Terms. The CISDT made minor clarifying edits of several of the definitions based on these comments. These proposed defined terms are being posted for a final ballot.

Revisions to Defined Terms in the NERC Glossary

- **Dynamic Interchange Schedule or Dynamic Schedule:** A time-varying energy transfer that is updated in R~~r~~eal-time and included in the Net Interchange Schedule~~d~~ term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Pseudo-Tie:** A time-varying energy transfer that is updated in R~~r~~eal-~~-~~time and included in the Net Interchange Actual term (NI_A) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Confirmed Interchange** - The state where no party has denied and all required parties have approved the Arranged Interchange.
- **Adjacent Balancing Authority** - A Balancing Authority whose Balancing Authority Area ~~that~~ is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
- **Intermediate Balancing Authority** - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
- **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any~~the~~ resulting Interchange Schedule.
- **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for ~~the~~ any resulting Interchange Schedule.
- **Operational Planning Analysis:** An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Proposed additional Defined Terms to be added to the NERC Glossary

- **Reliability Adjustment Arranged Interchange** ~~-~~– A ~~R~~request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
- **Composite Confirmed Interchange –** The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
- **Attaining Balancing Authority:** A Balancing Authority bringing generation or load into its effective control boundaries through a ~~d~~Dynamic ~~t~~Transfer from the Native Balancing Authority.
- **Native Balancing Area:** A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a D~~d~~ynamic ~~t~~Transfer.

Implementation Plan

Project 2008-12: Coordinate Interchange Standards

Requested Approvals

- INT-004-3 — Dynamic Transfers
- INT-006-4 — Evaluation of Interchange Transactions
- INT-009-2 — Implementation of Interchange
- INT-010-2 — Interchange Initiation and Modification for Reliability
- INT-011-1 — Intra-Balancing Authority Transaction Identification

Requested Retirements

- INT-001-3 Interchange Information
- INT-003-3 Interchange Transaction Implementation
- INT-004-2 Dynamic Interchange Transaction Modifications
- INT-005-3 Interchange Authority Distributes Arranged Interchange
- INT-006-3 Response to Interchange Authority
- INT-007-1 Interchange Confirmation
- INT-008-3 Interchange Authority Distributes Status
- INT-009-1 Implementation of Interchange
- INT-010-1 Interchange Coordination Exemptions

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

- **Dynamic Interchange Schedule or Dynamic Schedule:** A time-varying energy transfer that is updated in Real-time and included in the Net Interchange Schedule term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Pseudo-Tie:** A time-varying energy transfer that is updated in Real-time and included in the Net Interchange Actual term (NI_A) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

- **Request for Interchange** - A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.
- **Arranged Interchange** - The state where a Request for Interchange (initial or revised) has been submitted for approval.
- **Confirmed Interchange** - The state where no party has denied and all required parties have approved the Arranged Interchange.
- **Adjacent Balancing Authority** - A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
- **Intermediate Balancing Authority** - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
- **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.
- **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.
- **Operational Planning Analysis:** An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Proposed additional Defined Terms to be added to the NERC Glossary

- **Reliability Adjustment Arranged Interchange** – A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
- **Composite Confirmed Interchange –** The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
- **Attaining Balancing Authority:** A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.
- **Native Balancing Area:** A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

Background

The standards were developed under Project 2008-12, Coordinate Interchange Standards. The drafting team revised the existing approved standards and grouped the requirements in distinct groupings within each standard. The drafting team developed a new standard, INT-011-1, Intra-Balancing Authority Transaction Identification, in response to a FERC directive in Order 693, paragraph 817:

> *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

The proposed revision to the definition of Operational Planning Analysis addresses a FERC Order 693 directive:

> *866. Accordingly, the Commission approves Reliability Standard INT-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.*

The Reliability Coordinator and Transmission Operator are required to perform an Operational Planning Analysis in existing IRO-008-1, Requirement R1 and in TOP-002-3, Requirement R1 which was filed with FERC on April 16, 2013. By including the term "Interchange" explicitly in the definition, the drafting team has addressed the directive.

Applicable Entities

- Balancing Authority
- Transmission Service Provider
- Load-Serving Entities

Effective Date

First day of the second calendar quarter beyond the date each standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date each standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

Midnight of the day immediately prior to the Effective Date of the new standards in the particular jurisdiction in which the new standards are becoming effective.

Implementation Plan for Definitions

Entities shall use all proposed definitions when implementing any requirements within the new standards which use the defined term(s).

Implementation Plan for INT-004-3, Requirement R3

Requirement R3 is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. A request to revise the NAESB Electric Industry Registry has already been submitted for implementation. This requirement will become effective on the first calendar day two calendar quarters after the NAESB Electric Industry Registry is able to accept Pseudo-Tie registrations. All existing and future Pseudo-Ties are to be registered in the NAESB Electric Industry Registry.

Implementation Plan

Project 2008-12: Coordinate Interchange Standards

Requested Approvals

- INT-004-3 — Dynamic Transfers
- INT-006-4 — Evaluation of Interchange Transactions
- INT-009-2 — Implementation of Interchange
- INT-010-2 — Interchange Initiation and Modification for Reliability
- INT-011-1 — Intra-Balancing Authority Transaction Identification

Requested Retirements

- INT-001-3 Interchange Information
- INT-003-3 Interchange Transaction Implementation
- INT-004-2 Dynamic Interchange Transaction Modifications
- INT-005-3 Interchange Authority Distributes Arranged Interchange
- INT-006-3 Response to Interchange Authority
- INT-007-1 Interchange Confirmation
- INT-008-3 Interchange Authority Distributes Status
- INT-009-1 Implementation of Interchange
- INT-010-1 Interchange Coordination Exemptions

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

- **Dynamic Interchange Schedule or Dynamic Schedule:** A time-varying energy transfer that is updated in R~~r~~eal-time and included in the Net Interchange Schedule~~d~~ term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Pseudo-Tie:** A time-varying energy transfer that is updated in R~~r~~eal-~~-~~time and included in the Net Interchange Actual term (NI_A) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

- **Request for Interchange** - A collection of data as defined in the NAESB Business Practice Standards~~, to be~~ submitted ~~to the Sink Balancing Authority~~ for the purpose of implementing bilateral Interchange between ~~a Source and Sink~~ Balancing Authorities~~y~~ or an energy transfer within a single Balancing Authority.
- **Arranged Interchange** - The state where a Request for Interchange ~~the Sink Balancing Authority~~ (initial or revised) has been submitted for approval. ~~has received the Interchange information or intra-Balancing Authority transfer information (initial or revised).~~
- **Confirmed Interchange** - The state where no party has denied and all required parties have approved the Arranged Interchange.
- **Adjacent Balancing Authority** - A Balancing Authority whose Balancing Authority Area ~~that~~ is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
- **Intermediate Balancing Authority** - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
- **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any~~the~~ resulting Interchange Schedule.
- **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for ~~the~~ any resulting Interchange Schedule.
- **Operational Planning Analysis:** An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Proposed additional Defined Terms to be added to the NERC Glossary

- **Reliability Adjustment Arranged Interchange** ~~-~~– A ~~R~~request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
- **Composite Confirmed Interchange –** The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
- **Attaining Balancing Authority:** A Balancing Authority bringing generation or load into its effective control boundaries through a ~~d~~Dynamic ~~t~~Transfer from the Native Balancing Authority.
- **Native Balancing Area:** A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a D~~d~~ynamic ~~t~~Transfer.

Background

The standards were developed under Project 2008-12, Coordinate Interchange Standards. The drafting team revised the existing approved standards and grouped the requirements in distinct groupings within each standard. The drafting team developed a new standard, INT-011-1, Intra-Balancing Authority Transaction Identification, in response to a FERC directive in Order 693, paragraph 817:

> *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

The proposed revision to the definition of Operational Planning Analysis addresses a FERC Order 693 directive:

> *866. Accordingly, the Commission approves Reliability Standard INT-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.*

The Reliability Coordinator and Transmission Operator are required to perform an Operational Planning Analysis in existing IRO-008-1, Requirement R1 and in TOP-002-3, Requirement R1 which was filed with FERC on April 16, 2013. By including the term "Interchange" explicitly in the definition, the drafting team has addressed the directive.

Applicable Entities

- Balancing Authority
- Transmission Service Provider
- Load-Serving Entities

Effective Date

First day of the second calendar quarter beyond the date each standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date each standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

Midnight of the day immediately prior to the Effective Date of the new standards in the particular jurisdiction in which the new standards are becoming effective.

Implementation Plan for Definitions

Entities shall use all proposed definitions when implementing any requirements within the new standards which use the defined term(s).

Implementation Plan for INT-004-3, Requirement R3

Requirement R3 is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. A request to revise the NAESB Electric Industry Registry has already been submitted for implementation. This requirement will become effective on the first calendar day two calendar quarters after the NAESB Electric Industry Registry is able to accept Pseudo-Tie registrations. All existing and future Pseudo-Ties are to be registered in the NAESB Electric Industry Registry.

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Project 2008-12 - Coordinate Interchange Standards

Mapping Document

Project Purpose

The purpose of Project 2008-12 is to revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange. The drafting team also addressed the Interchange Subcommittee concerns related to the dynamic Transfers and Pseudo-ties and addressed previously identified stakeholder comments and applicable directives from Order 693. These issues and directives include defining communications on reloading interchange transactions due to different operational conditions and to bringing the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for: **R1.1.** All Dynamic Schedules at the expected average MW profile for each hour. Independent Expert Review recommendation: Retain Requirement.	Revised and Moved into INT-004-3	**INT-004-3:** **R1.** Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*] CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.
R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority: **R2.1.** If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator. **R2.2.** For each bilateral Inadvertent Interchange payback. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Retired	The CI SDT believes that this requirement is no longer necessary for reliability. Since the proposed INT-009-2 R1 makes it clear that the Net Scheduled Interchange term in the control equation can only include Confirmed Interchange as agreed to between Balancing Authorities, this by definition requires that an Arranged Interchange be created in order to implement the schedules listed in R2.1 and R2.2. From a reliability perspective, it is unimportant who creates these Arranged interchanges – only that they be created and confirmed prior to being entered into the control equation. CISDT Consideration of Independent Expert Review

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		recommendation: The CISDT concurs.

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. **R1.1.** The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including: **R1.1.1.** Interchange Schedule start and end time. **R1.1.2.** Energy profile. **R1.2.** If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing	Revised and Moved into INT-009-2	**INT-009-2:** R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign or direction to that of the

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie. Independent Expert Review recommendation: Retain Requirement.		Adjacent Balancing Authority. R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual (NI_A) term of their respective control ACE (or alternate control process). [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] R3. Each Balancing Authority in whose area the HVDC tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie. [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations, Operations Planning] CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Retired	The CI SDT believes that at a minimum, this requirement does not belong in the "Dynamic Schedules" standard. However, for several reasons, the CI SDT further believes that this specific requirement is no longer required: • It mandates a practice (releasing of E-Tag limits) that is process related. • The practice is already addressed in related NAESB standards (WEQ-004 Appendix B - E-Tag Actions). • Use of a limit (and the associated release of that limit) is only one particular way to address curtailments. Other ways exist that could be used in lieu of this approach. The reliability standard should not mandate a single approach when others may suffice. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.
R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the	Revised	**INT-004-2** **R2.** The Purchasing-Selling Entity that submitted a

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
tag is updated for the next available scheduling hour and future hours when any one of the following occurs: **R2.1.** The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +10%. **R2.2.** The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +25 megawatt-hours. **R2.3.** A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		Request For Interchange in accordance with Requirement R1, shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same Day Operations, Real Time Operations] 2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist. 2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist. 2.3. The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have the RFI updated for a Dynamic Schedule or Pseudo-Tie that is significantly different than the original schedule. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis.

Standard: INT-005-3, Interchange Authority Distributes Arranged Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange. **R1.1.** When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Retired	The CISDT is proposing retirement of this requirement. The entities to receive the transaction are included today in the eTag specification, Section 3.6.1.1.1. The timing requirement for the distribution of tags is removed from this standard, as they are currently included and expected to remain in the NAESB documentation. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange. **R1.1.** Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to: **R1.1.1.** Energy profile (ability to support the magnitude of the Interchange). **R1.1.2.** Ramp (ability of generation maneuverability to accommodate). **R1.1.3.** Scheduling path (proper connectivity of Adjacent Balancing Authorities). **R1.2.** Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the	Revised	R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange. 1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid. R2. Each Transmission Service Provider shall approve

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid. CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that this distribution requirement may currently drive how software performs this function. However, if that software were not present, this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		interchange to occur.

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following: **R1.1.** Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate). **R1.2.** All reliability entities involved in the Arranged Interchange are currently in the NERC registry. **R1.3.** The following are defined: **R1.3.1.** Generation source and load sink. **R1.3.2.** Megawatt profile. **R1.3.3.** Ramp start and stop times. **R1.3.4.** Interchange duration. **R1.4.** Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.	Retired, Revisions made to defined term used in various INT standards to clarify reliability objective	R1.1, R1.2 and R1.3 ensure the data submitted on the interchange is valid. This activity occurs in software validation and is not appropriate for a reliability standard; these items are included in the Technical Basis and Guidelines section of INT-006. Interchange that does not meet these criteria would not be an Arranged Interchange. R1.4. is addressed in the proposed revision to the definition of Confirmed Interchange: *The state where no party has denied and all required parties have approved the Arranged Interchange.* INT-006-4, Requirement R4 also specifies conditions under which the BA shall not transition to Confirmed Interchange: R4. Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: [Violation Risk Factor: Lower] [Time

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		Horizon: Operations Planning, Same-day Operations, Real-time Operations] • It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition. • It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition. • It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-008-3, Interchange Authority Distributes Status		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange. **R1.1.** For Confirmed Interchange, the Interchange Authority shall also communicate: **R1.1.1.** Start and stop times, ramps, and megawatt profile to Balancing Authorities. **R1.1.2.** Necessary Interchange information to NERC-identified reliability analysis services. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised and moved into INT-006-4	**INT-006-4:** R5. Each Sink Balancing Authority shall distribute all notifications of whether an Arranged Interchange was transitioned to Confirmed Interchange to the following entities, and notifications of on-time Confirmed Interchange shall be distributed such that they are delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 5.1. The Source Balancing Authority, 5.2. Each Intermediate Balancing Authority, 5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange, 5.4. Each Transmission Service Provider included in the Arranged Interchange, and 5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

Standard: INT-008-3, Interchange Authority Distributes Status		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that this distribution requirement may currently drive how software performs this function. However, if that software were not present, this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the interchange to occur.

Standard: INT-009-1, Implementation of Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Combined with INT-003-3, Requirement R1	**INT-009-2** **R1.** Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs that a separate requirement is not necessary. This requirement was combined with INT-003-3, Requirement R1.

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised	**INT-010-2:** **R1.** The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		data for reliability analysis
R2. For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised	**INT-010-2:** **R2.** Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R3. For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised	**INT-010-2:** **R3.** Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis

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Standard Authorization Request Form

Title of Proposed Standard	Modifications to Coordinate Interchange Standards for Applicability and General Upgrade
Request Date	May 27, 2008
Modified Date	December 1, 2008

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Interchange Subcommittee	☐	New Standard
Primary Contact Don Lacen, IS Chair	☒	Revision to existing Standards INT-001-2 — Interchange Transaction Tagging INT-003-2 — Interchange Transaction Implementation INT-004-1 — Interchange Transaction Modifications INT-005-2 — Interchange Authority Distributes Arranged Interchange INT-006-2 — Response to Interchange Authority INT-007-1 — Interchange Confirmation INT-008-2 — Interchange Authority Distributes Status INT-009-1 — Implementation of Interchange INT-010-1 — Interchange Coordination Exemptions
Telephone 505-241-2032 Fax 505-241-2582	☐	Withdrawal of existing Standard
E-maildon.lacen@pnm.com	☐	Urgent Action

Purpose **(Describe the proposed standard action: Nomination of a proposed standard, revision to a standard, or withdrawal of a standard and describe what the standard action will achieve.)** Revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange; to address the Interchange Subcommittee concerns related to the Dynamic Transfers and Pseudo-ties; to address previously identified stakeholder comments

and applicable directives from Order 693; to define communications on reloading interchange transactions due to different operational conditions; and to bring the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.
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.) There is confusion regarding the Interchange Authority "function". The need for improved clarity became apparent when entities were recently asked to register in the Compliance Registry as "Interchange Authorities" and entities had difficulty determining which entities were performing the Interchange Authority tasks identified in the set of Coordinate Interchange standards. The Interchange Authority activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities. The Coordinate Interchange standards dealing with the Interchange Authority and the current Functional Model representations of the Interchange Authority do not reflect technological advances made since the Functional Model working group originally defined the Interchange authority and advances made since the Coordinate Interchange standards were written. There are different interpretations surrounding the requirements associated with Dynamic Transfers and Pseudo-ties. Adding definitions for the terms used to reference Dynamic Transfers and Pseudo-ties (e.g., Dynamic Schedule, Dynamic Transfer, Pseudo-tie, Dynamic Schedule Curtailment) will add clarity to these requirements. Additional requirements may be needed to address the principles outlined in the Interchange Subcommittee's Principles and Definitions Supporting Dynamic Transfers and Pseudo-ties. (Attachment 2) Review the current NERC Glossary of Terms related to interchange to determine if any revisions or new definitions are necessary as a result of the Interchange standards development. The work in this project should be addressed in at least two phases with a ballot conducted at the end of each phase. The first phase is needed as soon as possible and should focus on the revisions needed to ensure that each requirement is assigned to a user, owner or operator of the bulk power system. All other proposed revisions should be addressed in the second or subsequent phase(s) of the project.
Brief Description (Provide a paragraph that describes the scope of this standard action.) The modifications in the set of Coordinate Interchange Standards should address the following: – Determine if the activities in the Coordinate Interchange standards correctly identify the responsible entity. – Consider requiring each Sink Balancing Authority or its designee to be responsible for providing the Interchange Authority functions using an interchange transaction tool process as defined in the latest approved version of the e-Tag

Specifications.

- The existing requirements are tool-neutral. Consider adding specific references to the e-Tagging process, applications, and tools in the requirements
- Consider adding a requirement to have backup capability for use when the interchange transaction tool fails.
- Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to follow.
- Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factor drafting team. (See Attachment 1)
- Determine if there is industry-wide support for the Interchange Subcommittee's Principles and definition supporting dynamic transfers and pseudo-ties, and if there is support, modify the requirements and add definitions accordingly.
- If there are no tasks assigned to the Interchange Authority function, then make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity.

Make other changes to the standards to bring them into conformance with the latest version of the Reliability Standards Development Procedure, Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

The work in this project should be done in two or more phases, with the first phase focused solely on clarifying the applicability of each requirement in the existing set of standards. All other revisions should take place in a second or subsequent phase(s).

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Revise the following set of Coordinate Interchange Standards so that the responsibility for each of the requirements is clearly assigned to an owner, operator or user of the bulk power system, and not to a tool.

INT-001-2 — Interchange Transaction Tagging
INT-003-2 — Interchange Transaction Implementation
INT-004-1 — Interchange Transaction Modifications
INT-005-2 — Interchange Authority Distributes Arranged Interchange
INT-006-2 — Response to Interchange Authority
INT-007-1 — Interchange Confirmation
INT-008-2 — Interchange Authority Distributes Status
INT-009-1 — Implementation of Interchange
INT-010-1 — Interchange Coordination Exemptions

Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to follow.

Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factor drafting team. (See Attachment 1)

Address the principles and definitions proposed by the Interchange Subcommittee in support of dynamic transfers and pseudo-ties. (See Attachment 2)

Make other changes to the standards to bring them into conformance with the latest version of the Reliability Standards Development Procedure, Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

If there are no tasks assigned to the Interchange Authority function, then make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity.
The work in this project should be addressed in at least two phases with a ballot conducted at the end of each phase. The first phase is needed as soon as possible and should focus on the revisions needed to ensure that each requirement is assigned to a user, owner or operator of the bulk power system. All other proposed revisions should be addressed in the second or later phases of the project.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	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 a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	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.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	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
CIP-002-1 through CIP-009-1	If the industry determines that the IA Function is not an "owner, operator or user" of the BES, then the applicability section of these standards should be modified to remove the IA as a responsible entity.

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1

(Issues originally intended for Project 2009-03 – Interchange Information)

INT-001-2 Interchange Information

Directives from FERC Order 693

- Include a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and “non-Order No. 888” transfers.
- Consider Santa Clara’s comments about the applicability of the LSE in the standard as part of the standards development process.

V0 Industry Comments

- R1 - Too stringent
- R1 – Who tags dynamic schedules?
- Load PSE responsibility is new restriction
- Clarify tagging of reserves
- R2.2 – 60 minute time frame questioned
- Question on generation scheduling
- Onerous to BA’s
- More commercial problem than reliability
- Lack of compliance

VRF Comments

- R1, 1.1, 2, 2.1, 2.2 – commercial and administrative

INT-003-2 Interchange Transaction Implementation

Unresolved Directives from FERC Order 693 – none

VRF Comments

- R1, 1.1, 1.1.2, 1.2 – commercial and administrative

INT-004-1 Dynamic Interchange Transaction Modifications

Unresolved Directives from FERC Order 693 – none

V0 Industry Comments

- Replace TSP with TOP
- Need to address tag curtailment
- Suggested non-compliance levels
- Non-compliance based on %
- Use WECC criteria

VRF Comments

- R2, 2.2, 2.3 – commercial and administrative

INT-005-2 Interchange Authority Distributes Arranged Interchange

Unresolved Directives from FERC Order 693 – none

VRF Comment

- R5 – administrative

INT-006-2 Response to Interchange Authority

Directives from FERC Order 693

- Include reliability coordinators and transmission operators as applicable entities.
- Require reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities' necessary transaction modifications before implementation.
- Consider the suggestions made by EEI and TVA and address questions raised by Entergy and Northern Indiana as part of the standard development process.

INT-007-1 Interchange Confirmation

Unresolved Directives from FERC Order 693 – none

VRF Comment

- R1, 1.1, 1.3, 1.3.1, 1.3.2, 1.3.3, 1.3.4, 1.4 – administrative

INT-008-2 Interchange Authority Distributes Status

Directives from FERC Order 693

- Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

VRF Comments

- R1.1.1 & 1.1.2 – commercial and administrative

INT-009-1 Implementation of Interchange

Directives from FERC Order 693

- Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

INT-010-1 Interchange Coordination Exemptions

Directives from FERC Order 693

- Consider Northern Indiana's and ISO-NE's suggestions in the standards development process.

VRF Comments

- R1 & 3 – administrative

Attachment 2 – Interchange Subcommittee's Principles and Definitions for Dynamic Schedules and Pseudo-ties

Dynamic Schedules

A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between balancing areas. A dynamic schedule must not change a balancing area's jurisdiction; that is, the native balancing area continues to exercise operational jurisdiction over, and provides basic balancing area services to, the dynamically scheduled resources.

All dynamic schedules used to assign the control of generation, loads, or resources from one balancing area to another must meet the following requirements:

1. Telemetry

1.1. Appropriate telemetry for a dynamic schedule must be in place and incorporated by all affected balancing areas. Standards requirements associated with this should address appropriateness issues related to accuracy, sampling rate, etc. which would impact reliability. For example, the relationship of BAL-005-1 R10 and BAL-005-1, R16 should be confirmed.

2. Transmission Service

2.1. Prior to implementation of the dynamic schedule of load or generation, it is the obligation of each involved balancing area to ensure that the dynamic schedule is implemented such that the tariff requirements of the applicable transmission provider(s) are met, including applicable ancillary services and provision of losses.

2.2. If transmission service between the source and sink balancing areas is curtailed then the allowable range of the magnitude of the schedules between them, including dynamic schedules, must be curtailed accordingly. Since dynamic schedules are implemented in ACE via telemetry, curtailment of e-Tags associated with dynamic schedules must be complemented with appropriate adjustments to the telemetered values used in ACE to make the curtailment be physically implemented via ACE control action.

3. System Modeling

3.1. Each balancing area must ensure that the dynamic transfer of load or generation through a dynamic schedule is coordinated with the Reliability Coordinator(s) with responsibility over the native, attaining, and contract intermediary balancing areas so that the dynamic schedule can be properly implemented in the system modeling of the affected generation or load, and necessary data provision requirements are met. Coordination must include tagging of the resultant scheduled interchange for use by other transmission providers and balancing areas for system security analysis and calculation of ATC.

3.2. When a dynamic schedule is used to serve load within another balancing area, the balancing area where the load is electrically connected (native balancing area) must include that load in its balancing area load forecast and any subsequent reporting as needed. This is necessary because the system models must adequately capture the projected demand on the system (load forecast), and the projected supply (provided by the electronic tagging system).

4. Dynamic Schedule Coordination and Scheduling

4.1. Although implemented in the ACE via telemetry, implementation of a dynamic schedule for NERC-identified reliability analysis services must be through the use of an interchange transaction between balancing areas. As such, all dynamic schedules must be tagged and implemented in accordance with NERC Standards.

4.2. Energy exchanged between the source, sink, and intermediary balancing areas as a dynamic schedule is the metered or calculated (obtained by the integration of the dynamic schedule signal over the operating hour) energy for the loads and/or resources for the hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.
4.3. The native balancing area must ensure that agreements are in place defining the responsibility for providing applicable ancillary/interconnected operations services.
4.4. The drafting team should consider reliability impacts and draft appropriate standards related to how dynamic schedules are modeled from various perspectives such as level of detail (i.e. degree to which composite representation is allowed such as each generator having dynamic schedule or allowing a composite plant dynamic schedule) and use of block schedules to serve part of a dynamic schedule. In the latter case, although a single telemetered value may be used in the ACE for a load, it can be represented in the e-Tagging by a combination of one or more block schedules for part of the load and a dynamic schedule for the remainder to represent the dynamic nature of a load.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the dynamic schedule on a plan for how the balancing areas will operate during a loss of the dynamic schedule telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.
5.2. The native balancing area, attaining balancing area and intermediary balancing areas shall agree before implementation of the dynamic schedule upon a plan for how the load will be served during abnormal system conditions including periods of time when the transfer path between them is unavailable. The native balancing area, attaining control area and intermediary balancing areas shall also agree before implementation of the dynamic schedule as to how the generation serving the dynamic schedule will respond during abnormal system conditions, including periods of time when the transfer path between them is unavailable.

Pseudo-Ties
Pseudo-ties are often employed to assign generators, loads, or both from the balancing area to which they are physically connected into a balancing area that has effective operational control of them. Thus, pseudo-ties provide for change of balancing area jurisdiction from the native to the attaining balancing area and at the same time make the attaining balancing area provider of balancing area services. This methodology is also referred to as "AGC Interchange" or "Non-Contiguous Pool Tie." In practice, pseudo-ties may be implemented based upon metered or calculated values. All balancing areas involved account for the power exchange and associated transmission losses as actual interchange between the balancing areas, both in their ACE equations and throughout all of their energy accounting processes.

All pseudo-ties used to assign generation, loads, or resources from the native balancing area to the attaining balancing area must meet the following requirements:
1. Telemetry
1.1. Appropriate telemetry must be in place and incorporated by all affected balancing areas.

2. Transmission Service
2.1. Prior to implementation of the dynamic transfer of load or generation by pseudo-tie, each involved balancing area shall ensure that the pseudo-tie is implemented such that the

tariff requirements of the applicable transmission provider(s), including applicable ancillary services and provision of losses, are met.
2.2. If transmission service between the native and attaining balancing areas is curtailed, then the allowable range of the magnitude of the pseudo-ties between them must be limited accordingly to these constraints. Since pseudo-ties are implemented in ACE via telemetry, appropriate adjustments must be made to the telemetered values used in ACE to make a curtailment be physically implemented via ACE control action.
2.3. Pseudo-ties must be implemented on firm transmission and are subject to curtailment on a pro rata basis with other firm transactions.

3. System Modeling
3.1. The assignment of load or generation into the control response of another balancing area must be appropriately captured in the IDC and security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators. It is the obligation of each balancing area to ensure that the dynamic transfer of load or generation by pseudo-ties is coordinated with the Reliability Coordinator(s) that have responsibility over the native, attaining, and contract intermediary balancing areas so that the pseudo-tie can be properly implemented in the system modeling of the generation or load affected, and necessary data provision requirements are met.
3.2. The attaining balancing area dynamically transferring load into its effective boundaries through a pseudo-tie shall ensure that load forecasts and subsequent balancing area reporting reflect the load incorporated within its balancing area boundaries.
3.3. If the reliability impact of the pseudo-tie cannot be accurately captured in the IDC and the security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators, the parties must implement the dynamic transfer either through use of a dynamic schedule, or through a combined implementation of pseudo-tie and dynamic schedule where the load or generation within the native balancing area is separately modeled in the IDC.
3.4. The drafting team should consider clarifying how pseudo-tie can be used in reliability analysis activities. For example, since they are not physical ties, should they be omitted from being used as part of a defined flowgate and in physical interface calculations yet be included in inadvertent calculations

4. Pseudo-Ties Coordination and Scheduling
4.1. Subsequent to moving load or resources into an attaining balancing area through pseudo-ties, all interchange transactions or other energy transfers to the loads or from the resources must be coordinated by the attaining balancing area.
4.2. The attaining balancing area assumes responsibility for balancing area services required by the assigned loads and/or resources. The attaining balancing area assumes all regulation, contingency reserves, and other balancing area responsibilities for the loads and/or resources in question.
4.3. Energy exchanged between the native and attaining balancing areas by the pseudo-tie method is accounted for by the associated revenue meter reading for the operating hour (if such meter exists at the dynamically assigned resource or load) or energy calculated by integrating the associated telemetered real-time signal over the operating hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie on a plan for how the balancing areas will operate during a loss of the pseudo-tie telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good

value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

5.2. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie upon a plan for how the load will be served during abnormal system conditions including periods of time when the interconnection between them is lost. The native balancing area, attaining balancing area, and intermediary balancing areas shall also agree before implementation of the pseudo-tie how the entities will respond during abnormal system conditions, including periods of time when the connection between them is unavailable.

Dynamic Transfer Reference Document

The Drafting Team should take the existing Dynamic Transfer Reference Document, update it as necessary to reflect Functional Model terms and any changes necessary as a result of new requirements from the standards drafting resulting from this SAR and submit it for ballot as a formal reference document linked to those standards. This will provide the industry with a formal, official document to provide guidance on the implementation of dynamic transfers covered in the standards.

The Interchange Subcommittee recommends moving INT-001 standard requirement R.1. to a more appropriate INT standard such as INT-001 or INT-003.

Note: In addition to the above requirements, the NERC Glossary of Terms may need to be amended to include the following new or revised definitions:

ATTAINING BALANCING AREA — A balancing area bringing generation or load into its effective control boundaries through dynamic transfer from the Native Balancing area.

DYNAMIC SCHEDULE — A telemetered reading, or value that is updated in real-time and used as a schedule in the AGC/ACE equation of the affected balancing areas and the integration of which is treated as a schedule for interchange accounting purposes. To the extent that no associated energy metering equipment exists, the integration of the telemetered real time signal is used as a scheduled MWh value for interchange accounting purposes.

DYNAMIC TRANSFER — The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to implement a dynamic schedule or pseudo-tie.

INTEGRATION in the context of dynamic schedules and pseudo-ties means the value could be mathematically calculated or determined mechanically with a metering device.

INTERCONNECTED OPERATIONS SERVICE (IOS) — A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected bulk electric systems.

NATIVE BALANCING AREA — A balancing area from which a portion of its physically interconnected generation and/or load is assigned from its effective control boundaries through dynamic transfer to the attaining balancing area.

PSEUDO-TIE — A telemetered reading, or value that is updated in real time, representative of generation or load assigned dynamically between balancing areas and used as a tie line flow in the affected balancing areas' AGC/ACE equation, but for which no physical balancing area tie actually exists. To the extent that no associated energy metering equipment exists,

the integration of the telemetered real time signal is used as a metered MWh value for interchange accounting purposes.

Project 2008-12: Coordinate Interchange Standards

VRF and VSL Justifications for INT-006-4

VRF and VSL Justifications – INT-006-4, R1	
Proposed VRF	Lower
NERC VRF Discussion	Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-006-3, R1, which deals with responding to on-time RFI, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR

VRF and VSL Justifications – INT-006-4, R1	
	The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange. OR The Scheduling Path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-006-4, R1	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to take action on an on-time Arranged Interchange or an emergency Arranged Interchange, or for failing to deny an Arranged Interchange under certain circumstances.

VRF and VSL Justifications – INT-006-4, R2	
Proposed VRF	Lower
NERC VRF Discussion	Transmission Service Providers must take action on a received Arranged Interchange within a certain time frame. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-006-3, R1, which deals with responding to on-time RFI, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – INT-006-4, R2	
Proposed High VSL	N/A
Proposed Severe VSL	The Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-006-4, R2	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to take action on an on-time Arranged Interchange or an emergency Arranged Interchange, or for failing to deny an Arranged Interchange or curtail Confirmed Interchange under certain circumstances.

VRF and VSL Justifications – INT-006-4, R3	
Proposed VRF	Lower
NERC VRF Discussion	Source or Sink Balancing Authorities receiving a Reliability Adjustment Arranged Interchange need to approve or deny it prior to the expiration of the reliability assessment period defined in the timing requirements. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-006-3, R1, which deals with approving or denying Arranged Interchange is submitted, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A

VRF and VSL Justifications – INT-006-4, R3	
Proposed Moderate VSL	N/A
Proposed High VSL	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.
Proposed Severe VSL	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: Not applicable. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-006-4, R3	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to act on a Reliability Adjustment Arranged Interchange within a certain time frame, or for failing to communicate a denial to the Reliability Coordinator within 10 minutes of the denial.

VRF and VSL Justifications – INT-006-4, R4	
Proposed VRF	Lower
NERC VRF Discussion	Balancing Authorities should not transition Arranged Interchange to Confirmed Interchange under certain conditions. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-007-13, R1, which deals with ensuring Arranged Interchanges is valid before transitioning to Confirmed Interchange, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A

VRF and VSL Justifications – INT-006-4, R4	
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning an Arranged Interchange to Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of	The VSL is assigned for a single instance of transitioning an Arranged Interchange to Confirmed Interchange under certain circumstances under which an Interchange should not be transitioned.

VRF and VSL Justifications – INT-006-4, R4	
Violations	

VRF and VSL Justifications – INT-006-4, R5	
Proposed VRF	Lower
NERC VRF Discussion	Distributing information regarding whether an Arranged Interchange was transitioned to Confirmed Interchange is necessary to ensure that everyone has the same information regarding the transactions. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-008-3, R1, which deals with distributing information regarding whether an Arranged Interchange was transitioned to Confirmed Interchange, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	The Sink Balancing Authority did not distribute notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to all of the entities listed in Requirement R5 Parts 5.1-5.5.

VRF and VSL Justifications – INT-006-4, R5	
Proposed Severe VSL	The Sink Balancing Authority did not notify any of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange. OR The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify one or more of the entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: Not applicable. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4	The VSL is assigned for a single instance of failing to distribute

VRF and VSL Justifications – INT-006-4, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to specific entities.

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VRF and VSL Justifications for INT-009-2

VRF and VSL Justifications – INT-009-2, R1	
Proposed VRF	Medium
NERC VRF Discussion	Agreement between Balancing Authorities regarding the magnitude and direction of Composite Confirmed Interchange is necessary to ensure that each balancing Authority is controlling their generation for the proper amount of Interchange. If the values are not agreed to, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite

VRF and VSL Justifications – INT-009-2, R1	
	Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, excluding Dynamic Schedules and including any interchange as directed by a Reliability Coordinator per INT-010-2 not yet captured in the Composite Confirmed Interchange, for that hour.

VRF and VSL Justifications – INT-009-2, R2	
Proposed VRF	Medium
NERC VRF Discussion	Agreement between Balancing Authorities regarding the source to be used for a Pseudo-Tie is necessary to ensure that each balancing Authority is controlling their generation for the proper amount of Interchange associated with the Pseudo-Tie. If the values are not agreed to, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual (NI_A) term of their respective control ACE (or alternate control process).
FERC VSL G1 Violation Severity Level Assignments Should Not	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-009-2, R2	
Have the Unintended Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process).

VRF and VSL Justifications – INT-009-2, R3	
Proposed VRF	Medium
NERC VRF Discussion	Coordination of Interchange across HVDC is necessary to ensure that the Facility is operated within its limits and that each Balancing Authority is controlling to a correct Interchange value. If the interchange is not appropriately accounted for, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-009-2, R3	
the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie..

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VRF and VSL Justifications for INT-011-1

The drafting team will complete the following table, providing of analysis and justification for each VRF and VSL, for each requirement in INT-011-1—Intra-Balancing Authority Transaction Identification

VRF and VSL Justifications – INT-011-1, R1	
Proposed VRF	Lower
NERC VRF Discussion	Transfers within a Balancing Authority Area can potentially impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring that Arranged Interchange is submitted. This requirement is assigned a Lower VRF
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A

VRF and VSL Justifications – INT-011-1, R1	
Proposed Severe VSL	The Load-Serving Entity used Point to Point Transmission Service for an intra-Balancing Authority Area transfer, and did not submit a Request for Interchange for an intra-Balancing Authority transfer that is not included in congestion management procedure(s) via an alternate method.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted or the transfer is not included in congestion management procedure(s) via an alternate method.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	The VSL is assigned for a single instance of failing to submit a Request for Interchange or include the transfer in congestion management procedure(s) via an alternate method.

VRF and VSL Justifications – INT-011-1, R1	
on A Single Violation, Not on A Cumulative Number of Violations	

Consideration of Issues and Directives

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Issue or Directive	Source	Consideration of Issue or Directive
817. In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.	FERC Order 693, Paragraph 817	INT-011-1, R1 addresses the directive in FERC Order 693, Paragraph 817. While the Commission asked that the ERO modify INT-001-2 to address the directive, the Project 2008-12 has proposed INT-001-2 for retirement and thus, it is most appropriate to create a new standard that addresses the directive. The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and INT-011-1 ensures that these transfers are communicated and accounted for in congestion management procedures. If a transfer within a Balancing Authority Area is submitted as a Request for Interchange or otherwise accounted for in congestion management procedures, it can be evaluated and processed comparable to a Request for Interchange that crosses Balancing Authority Areas. **R1.** Each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange

Issue or Directive	Source	Consideration of Issue or Directive
		unless the information about intra-Balancing Authority transfers is included in congestion management procedure(s) via an alternate method. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations]*
819. With respect to Santa Clara's position that LSEs should be applicable entities under the Reliability Standard, the Commission notes that in situations where a LSE is securing energy from outside the balancing authority to supply its end-use customers, it would function as a purchasing-selling entity, as defined in the NERC glossary, and would be included in the NERC registry on that basis. This interpretation flows from the language of the Reliability Standards, and the Commission does not perceive any ambiguity in this connection. Nevertheless, the Commission directs the ERO to consider Santa Clara's comments, and whether some more explicit language would be useful, in the course of modifying INT-001-2 through the Reliability Standards development process.	FERC Order 693, Paragraph 819	The CISDT has retained the Purchasing Selling Entity the proposed INT standards and believes that general industry consensus supports the Purchasing-Selling Entity being the appropriate applicable entity.
843. As explained in the NOPR, while the Commission	FERC Order	The CISDT has added all compliance elements to the

Issue or Directive	Source	Consideration of Issue or Directive
has identified concerns with regard to INT-004-1, this proposed Reliability Standard serves an important purpose by setting thresholds on changes in dynamic schedules for which modified interchange data must be submitted. Further, the Requirements set forth in INT-004-1 are sufficiently clear and objective to provide guidance for compliance. Accordingly, the Commission approves Reliability Standard INT-004-1 as mandatory and enforceable. In addition, the Commission directs the ERO to consider adding these Measures and Levels of Non-Compliance to the Reliability Standard.	693, Paragraph 843	standard, including VRFs, VSLs and Time Horizons. NOTE: FERC retired this directive on November 21, 2013 in Docket No. RM13-8-000.
848. The Commission is satisfied that the Requirements of INT-005-1 are appropriate to ensure that interchange information is distributed timely and available for reliability assessment. Accordingly, the Commission approves Reliability Standard INT-005-1 as mandatory and enforceable. In addition, the Commission directs the ERO to consider adding additional Measures and Levels of Non-Compliance to the Reliability Standard.	FERC Order 693, Paragraph 848	The CISDT has added all compliance elements to the standard, including VRFs, VSLs and Time Horizons. NOTE: FERC retired this directive in an order issued on November 21, 2013 in Docket No. RM13-8-000.
866. Accordingly, the Commission approves Reliability	FERC Order	See separate document regarding an equally efficient and

Issue or Directive	Source	Consideration of Issue or Directive
Standard INT-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.	693, Paragraph 866	effective method of addressing this directive. (Order 693 Paragraph 866 - CISDT White Paper)
871. APPA agrees with the Commission that INT-008-1 is sufficient for approval as a mandatory and enforceable Reliability Standard, subject to NERC's plans for the registration of entities as interchange authorities. It suggests that NERC should clarify which reliability entities have the responsibility for ensuring	FERC Order 693, Paragraphs 871 and 872	The Interchange Authority entity has been replaced with the Sink Balancing Authority throughout the INT standards.

Issue or Directive	Source	Consideration of Issue or Directive
that interchange information is coordinated between the source and sink balancing authorities before implementing the Reliability Standard. APPA also states that NERC should modify this Reliability Standard to make clear what entities it in fact would apply to. 872. The Commission approves Reliability Standard INT-008-1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that a source and sink balancing authority will serve as the interchange authority until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process. Finally, we direct the ERO to consider APPA's suggestions in the Reliability Standards development process.		
874. APPA agrees with the Commission that INT-009-1 is sufficient for approval as a mandatory and enforceable Reliability Standard, subject to NERC's plans for the registration of entities as interchange authorities. It suggests that NERC modify its Functional	FERC Order 693, Paragraphs 874 and 875	The Interchange Authority entity has been replaced with the Sink Balancing Authority throughout the INT standards.

Issue or Directive	Source	Consideration of Issue or Directive
Model to clarify which reliability entities have the responsibility for ensuring proper implementation of interchange transactions that have received reliability assessments. APPA also suggests that NERC modify this Reliability Standard to make clear what entities it in fact would apply to. 875. The Commission approves Reliability Standard INT-009-1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that a source and sink balancing authority will serve as the interchange authority until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process. Finally, we direct the ERO to consider APPA's suggestions concerning this Reliability Standard in the Reliability Standards development process.		
879. Northern Indiana supports the Commission's interpretation of INT-010-1, but it requests that the Reliability Standard be modified to explicitly state that it does not include actual IROL violations.	FERC Order 693, Paragraphs 879, 880 and	The CISDT has reviewed the comments of Northern Indiana and ISO-NE with respect to possible revisions to INT-010-1. The CSIDT has proposed a new defined term: **Reliability Adjustment Arranged Interchange –** A request to

Issue or Directive	Source	Consideration of Issue or Directive
880. ISO-NE supports Commission approval of INT-010-1, but does not share the Commission's concerns regarding the initiation or modification of interchange schedules to address SOL or IROL violations. It states that interchange schedules can in certain circumstances provide an additional effective tool to help prevent an SOL and IROL violation. While ISO-NE recognizes that other tools may in certain circumstances be more effective, it states that this neither diminishes the value nor precludes the use of the tools contained in INT-010-1. ISO-NE also notes that section 2.4 of INT-010-1, which describes Level 4 Non-Compliance, should be edited to state that "[t]here shall be a level four non-compliance. . . " instead of "[t]here shall be a level three non-compliance. . . ." 887. Accordingly, the Commission approves Reliability Standard INT-010-1 as mandatory and enforceable. In addition, we adopt the interpretation set forth in the NOPR that these current or imminent reliability-related reasons do not include actual IROL violations, since they require immediate control actions so that the system can be returned to a secure operating state as soon as possible and no longer than 30 minutes after a	887	modify a Confirmed Interchange or Implemented Interchange for reliability purposes. This proposed term is used in one requirement: R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations] The CISDT notes that submitting a revised tag within 60 minutes ensures that modification of interchange will not be used to relieve an IROL as most IROLs have to be mitigated within 30 minutes or a lesser value of T_v. The CISDT does not believe that additional specificity regarding actual IROL violations is necessary for this standard.

Issue or Directive	Source	Consideration of Issue or Directive
reliability-related system interruption – a period that is much shorter than the time that is expected to be required for new or modified transactions to be implemented. Finally, we direct the ERO to consider Northern Indiana and ISO-NE's suggestions in the Reliability Standards development process.		
On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: • Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define "Non-Asset Owning LSEs" as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset.	FERC's December 20, 2007 and April 4, 2008 Orders	The LSE entity is incorporated into the INT standards, but the requirements apply regardless of whether the LSE is an asset owning LSE or not.

Issue or Directive	Source	Consideration of Issue or Directive
• Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. Specifically, the following description has been incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that		

Issue or Directive	Source	Consideration of Issue or Directive
includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: • FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) • NERC's March 4, 2008		

Issue or Directive	Source	Consideration of Issue or Directive
(http://www.nerc.com/files/FinalFiledLSE3408.pdf), • FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and • NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.		
NAESB Standards Review Subcommittee as input to the Reliability Standards Development Plan: 2010-2012: NAESB requests that NERC engage in coordination with them as needed on this project as it relates to item 3.a.viii in the NAESB WEQ 2009 Annual Plan.	NAESB Standards Review Subcommittee	The NERC JESS has members on the CISDT and they are coordinating with NAESB on this project.
The SDT review the definitions of the following terms and coordinate with NAESB so that the definition of each term is consistent between NERC and NAESB: Interchange Schedule Interchange Transaction	NERC/NAESB Coordination	The CISDT has proposed revisions to some of these terms and members will coordinate revisions to them on the NAESB Glossary.

Issue or Directive	Source	Consideration of Issue or Directive
Interchange Transaction Tag (Tag) Request for Interchange Source BA Sink BA		
These terms reflect the continued use of the IA, and be consistent (not identical) between NERC and NAESB. Request for Interchange Arranged Interchange Confirmed Interchange	NERC/NAESB Coordination	The CISDT has proposed revisions to some of these terms and members will coordinate revisions to them on the NAESB Glossary. These terms have been revised to remove the Interchange Authority and to replace it with Sink Balancing Authority. **Request for Interchange -** A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority. **Arranged Interchange -** The state where a Request for Interchange (initial or revised) has been submitted for approval. **Confirmed Interchange -** The state where no party has

Issue or Directive	Source	Consideration of Issue or Directive
		denied and all required parties have approved the Arranged Interchange.
Changes to the INT standards and IRO standards to support Parallel Flow Visualization. This would include addressing the difference between what is "Interchange" and what is "tagged." Currently, INT standards do not require RFIs for internal transactions; and IRO-006-EAST does not mandate curtailment of internal PTP. NAESB may create interim business practices to support this, so we may have to work with them to retire their standards as ours come into effect.	NAESB	This issue is addressed through INT-011-1 and is related to the FERC Order 693 directive contained in Paragraph 817 above. With INT-011, the term Confirmed Interchange will include “Interchange Transactions” as well as “Intra-BA transfers”. The CISDT will provide input to the Five Year Review Team working on IRO-006-EAST suggesting that they replace the term “Interchange Transactions” with “Confirmed Interchange” to capture the appropriate transactions and flows.
Clarify tagging of reserves (INT-001-1)	Version 0 Team	The CISDT does not believe it is necessary (from a reliability perspective) to tag reserves that are not flowing.
Lack of compliance (INT-001-1)	Version 0 Team	Compliance elements were added to the standard including VRFs, VSLs, and Time Horizons.
Non-compliance based on % (INT-004-1)	Version 0	The VSLs now reflect a single violation of a requirement

Issue or Directive	Source	Consideration of Issue or Directive
	Team	rather than a percentage.
Onerous to BAs (INT-001-1)	Version 0 Team	The standard has been merged with INT-004. Requirement R2 was retired.
R1 - Too stringent (INT-001-1)	Version 0 Team	Requirement R1 was moved into INT-004-3 and revised R1. Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations]
R1 Who tags dynamic schedules? (INT-001-1)	Version 0 Team	This is addressed in INT-004-3, Requirement R1. R1. Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information

Issue or Directive	Source	Consideration of Issue or Directive
		about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations]
R2.2 60 minute time frame questioned (INT-001-1)	Version 0 Team	Requirement R2.2 was retired from the standard.
R1 & 3 administrative (INT-010-1)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements that are administrative per the guidelines set forth under the Paragraph 81 project.
R1, 1.1, 1.1.2, 1.2 commercial and administrative (INT-003-1)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements that are administrative per the guidelines set forth under the Paragraph 81 project.
R1, 1.1, 1.3, 1.3.1, 1.3.2, 1.3.3, 1.3.4, 1.4 administrative (INT-007-1)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements that are administrative per the guidelines set forth under the

Issue or Directive	Source	Consideration of Issue or Directive
		Paragraph 81 project.
R1, 1.1, 2, 2.1, 2.2 commercial and administrative (INT-001-1)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements that are administrative per the guidelines set forth under the Paragraph 81 project.
R1.1.1 & 1.1.2 – commercial and administrative (INT-008-2)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements that are administrative per the guidelines set forth under the Paragraph 81 project.
R2, 2.2, 2.3 commercial and administrative (INT-004-1)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements that are administrative per the guidelines set forth under the Paragraph 81 project.
R5 administrative (INT-005-2)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements that are administrative per the guidelines set forth under the Paragraph 81 project.

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Order 693 Paragraph 866

Project 2008-12 Coordinate Interchange Standard Drafting Team Solution
June 2013 (revised December 2013)

In Order No. 693, FERC issued several directives pertaining to the INT standards. This white paper explains how the Coordinate Interchange Standard Drafting Team (CISDT) proposes to address one of those directives through an equal and effective alternative.

Paragraph 866:

> *866. Accordingly, the Commission approves Reliability Standard INT-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.*

Based on feedback from the NERC Operating Committee as well as drafting team input, the CISDT proposes an equally efficient and effective method to address the directive, by revising an existing, approved NERC Glossary term, Operational Planning Analysis. The CISDT proposes revising the term as follows:

> **Operational Planning Analysis**: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

The term **Operational Planning Analysis** is used in standards that apply to both the Reliability Coordinator and the Transmission Operator entities.[1] Proposed Reliability Standard INT-006-4, Requirement R6 requires Interchange information to be provided to the Reliability Coordinator. This is typically achieved using the electronic tagging function.

> *R6.Each Sink Balancing Authority shall distribute all notifications of whether an Arranged*

[1] A comprehensive list of each Reliability Standard and Requirement that contains the tem Operational Planning Analysis is at the end of this document.

Interchange was transitioned to Confirmed Interchange to the following entities, and notifications of on-time Confirmed Interchange shall be distributed such that they are delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]

6.1. The Source Balancing Authority,

6.2. Each Intermediate Balancing Authority,

6.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,

6.4. Each Transmission Service Provider included in the Arranged Interchange, and

6.5. Each Purchasing Selling Entity included in the Arranged Interchange.

The IRO standards apply to the Reliability Coordinator, and Operational Planning Analysis is referenced in the requirements of IRO-008-1. Requirement R1 of IRO-008-1 specifies that the Reliability Coordinator must perform an Operational Planning Analysis:

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions. (Violation Risk Factor: Medium) (Time Horizon: Operations Planning)

By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider Interchange when performing the study. When the results of this study indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3 of IRO-008-1:

R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions. (Violation Risk Factor: Medium) (Time Horizon: Real-time Operations or Same Day Operations)

TOP-002-3 contains requirement for the Transmission Operator to perform an Operational Planning Analysis (Requirement R1) and to develop plans for reliable operations based on the results of the Operational Planning Analysis and notify other entities as to their role in those plans (Requirement R3).

*R1. Each Transmission Operator shall have an **Operational Planning Analysis** that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

*R2. Each Transmission Operator shall **develop a plan** to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its*

Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]
R3. Each Transmission Operator ***shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).*** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

While the INT standards do not require Interchange information to be provided to the Transmission Operator, it is expected that the Transmission Operator will rely on TOP-003-2, Requirements R1, R3, and R5 to obtain the information from Balancing Authorities.

R1. Each Transmission Operator shall create a documented specification for the ***data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.*** *The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.

1.2. A mutually-agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R3. Each Transmission Operator shall ***distribute its data specification, as developed in Requirement R1 to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process*** *used in meeting its NERC-mandated reliability requirements. [Violation Risk Factor: Low] [Time Horizon: Operations Planning]*
R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 ***shall satisfy the obligations of the documented specifications for data****. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The IRO standards shown above are mandatory and enforceable. The TOP standards are pending before FERC.

List of Requirements Containing the Term Operational Planning Analysis

Mandatory and Enforceable Standards:

- **IRO-008-1 – Reliability Coordinator Operational Analyses and Real-time Assessments, Requirements R1 and R3:**

  R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions. (Violation Risk Factor: Medium) (Time Horizon: Operations Planning)

  R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions. (Violation Risk Factor: Medium) (Time Horizon: Real-time Operations or Same Day Operations)

Board-approved Standards Pending Regulatory Approval

- **IRO-005-4 — Reliability Coordination — Current Day Operations, Requirement R1:**

  *R1.When the results of an **Operational Planning Analysis** or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area. [Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same Day Operations and Operations Planning]*
- **TOP-001-2 — Transmission Operations, Requirements R1 and R8:**

  R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: High] [Time Horizon: Operations Planning,]

  R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]
- **TOP-002-3 — Operations Planning, Requirements R1 and R2:**

  *R1. Each Transmission Operator shall have an **Operational Planning Analysis** that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

- **TOP-003-2 — Operational Reliability Data, Requirements R1 and R3:**

  *R1. Each Transmission Operator shall create a documented specification for the **data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.** The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

  1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.

  1.2. A mutually-agreeable format.

  1.3. A periodicity for providing data.

  1.4. The deadline by which the respondent is to provide the indicated data.

  R3. Each Transmission Operator shall distribute its data specification, as developed in Requirement R1, to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated Reliability requirements. [Violation Risk Factor: Low] [Time Horizon: Operations Planning]

A. Introduction

1. Title: **Response to Interchange Authority**

2. Number: INT-006-3

3. Purpose: To ensure that each Arranged Interchange is checked for reliability before it is implemented.

4. Applicability:

4.1. Balancing Authority.

4.2. Transmission Service Provider.

5. Effective Date: July 1, 2010

B. Requirements

R1. Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.[1]

R1.1. Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:

R1.1.1. Energy profile (ability to support the magnitude of the Interchange).

R1.1.2. Ramp (ability of generation maneuverability to accommodate).

R1.1.3. Scheduling path (proper connectivity of Adjacent Balancing Authorities).

R1.2. Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated.

C. Measures

M1. The Balancing Authority and Transmission Service Provider shall each provide evidence that it responded, relative to transitioning an Arranged Interchange to a Confirmed Interchange, to each On–time Request for Interchange (RFI), and to each Emergency RFI or Reliability Adjustment RFI from an Interchange Authority within the reliability assessment period defined in the Timing Table, Column B. The Balancing Authority and Transmission Service Provider need not provide evidence that it responded to any other requests.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be twelve months from the last non-compliance to Requirement 1.

[1] The Balancing Authority and Transmission Service Provider need not provide responses to any other requests.

1.3. Data Retention

The Balancing Authority and Transmission Service Provider shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

1.4. Additional Compliance Information

The Balancing Authority and Transmission Service Provider shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

Subsequent to the initial compliance review, compliance may be:

1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Interchange Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authority, and Transmission Service Provider shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records and agreements for the audit period which indicate a reliability entity identified in R1 responded to all instances of the Interchange Authority's communication under Reliability Standard INT-005 Requirement 1 concerning the pending transition of an Arranged Interchange to Confirmed Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority, or Transmission Service Provider.

1.4.6 For specific complaints, agreements and those data and system log records associated with the specific Interchange event contained in the complaint which indicates a reliability entity identified in R1 has responded to the Interchange Authority's communication under INT-005 R1 concerning the pending transition of Arranged Interchange to Confirmed Interchange for that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[2] of not responding to the Interchange Authority as described in R1.

2.2. Level 2: Two occurrences[1] of not responding to the Interchange Authority as described in R1.

2.3. Level 3: Three occurrences[1] of not responding to the Interchange Authority as described in R1.

[2] This does not include instances of not responding due to extenuating circumstances approved by the Compliance Monitor.

2.4. Level 4: Four or more occurrences[1] of not responding to the Interchange Authority as described in R1 or no evidence provided.

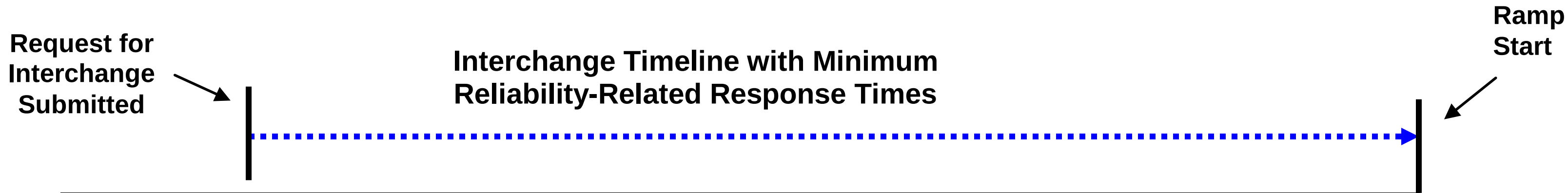
E. Regional Differences

None.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Approved by BOT	New
2	May 2, 2007	Approved by BOT	Revised
3	April 8, 2010	Approved by FERC, Effective July 1, 2010	

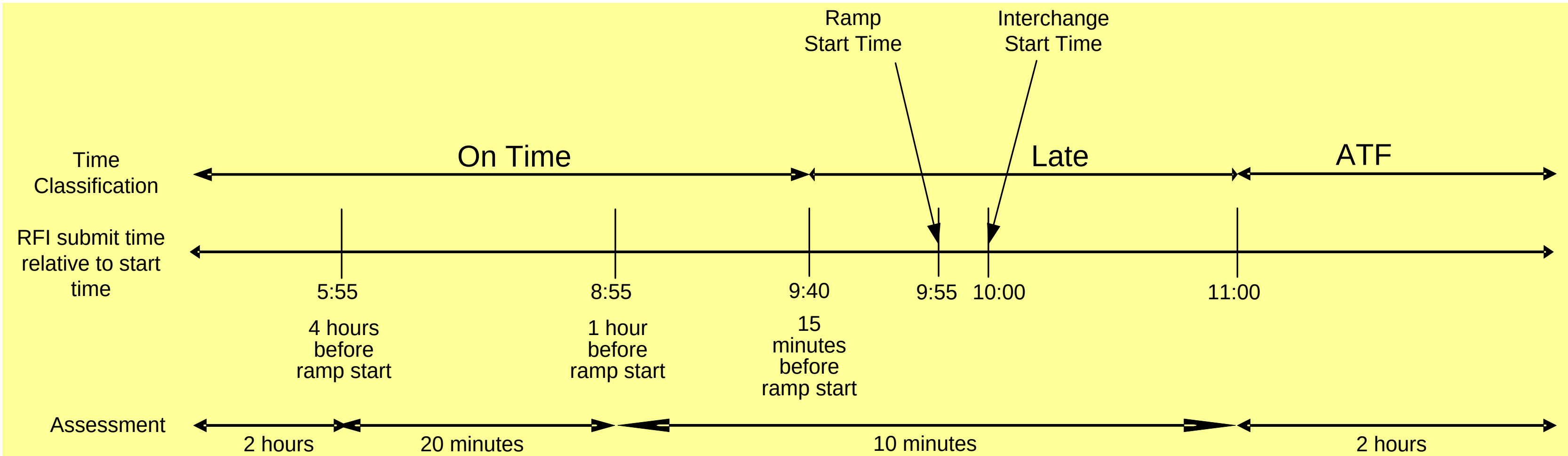
Timing Requirements for all Interconnections except WECC



		A	B	C	D
If Arranged Interchange (RFI)[3] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the RFI start time	ATF	≤ 1 minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1 minute from receipt of all Reliability Assessments	NA
<15 minutes prior to ramp start and ≤1 hour after the RFI start time	Late	≤ 1 minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1 minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 20 minutes from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1 minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1 minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for all Interconnections except WECC

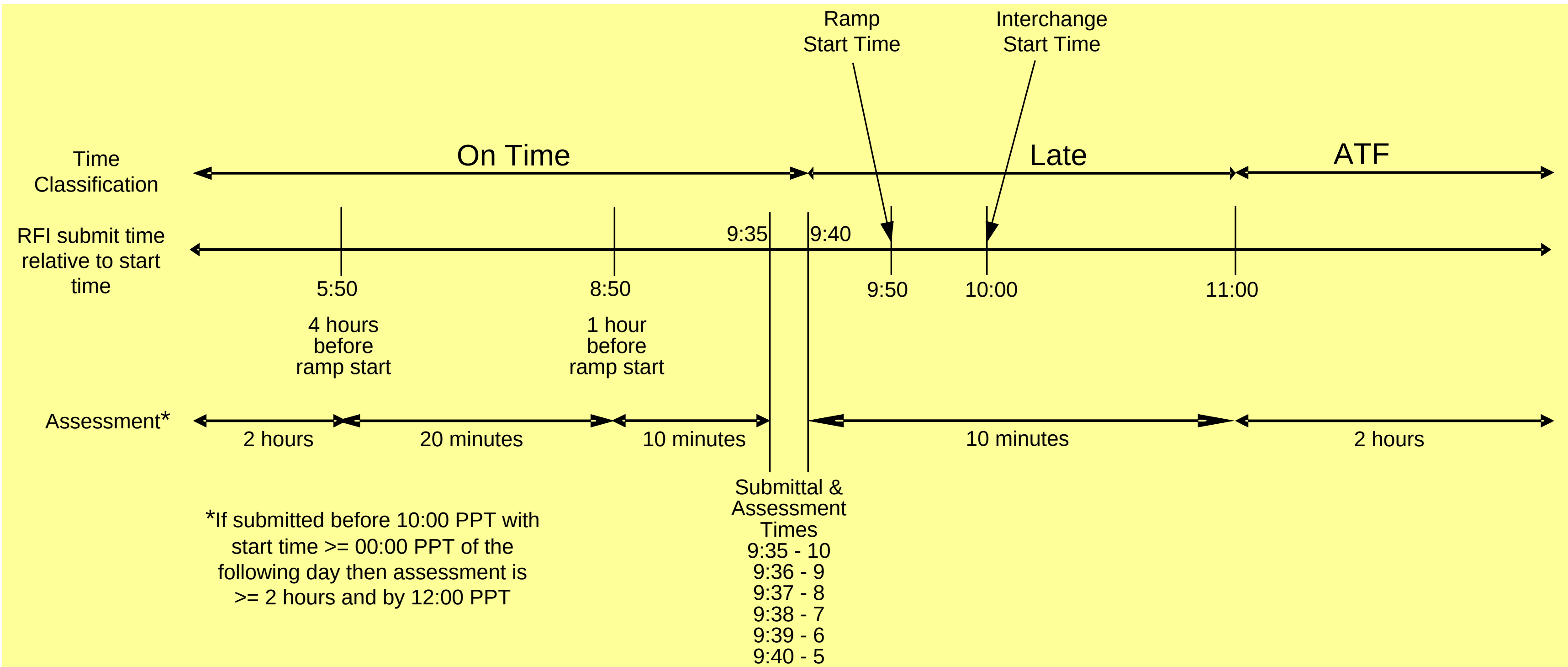


Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange (RFI)[4] is Submitted	**IA Assigned Time Classification**	**IA Makes Initial Distribution of Arranged Interchange**	**BA and TSP Conduct Reliability Assessments**	**IA Compiles and Distributes Status**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF	≤ 1minute from RFI submission	Entities have up to 2 hours to respond.	≤ 1minute from receipt of all Reliability Assessments	NA
<10 minutes prior to ramp start and ≤1 hour after the start time	Late	≤ 1minute from RFI submission	Entities have up to 10 minutes to respond.	≤ 1minute from receipt of all Reliability Assessments	≤ 3 minutes after receipt of confirmed RFI
10 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 5 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
11 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 6 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
12 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 7 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
13 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 8 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
14 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 9 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 10 minutes from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 3 minutes prior to ramp start
≥ 1hour and < 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	< 20 minutes from Arranged interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time	≤ 1minute from RFI submission	≤ 2 hours from Arranged Interchange receipt from IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time	≤ 1minute from RFI submission	By 12:00 PPT of day the Arranged Interchange was received by the IA	≤ 1minute from receipt of all Reliability Assessments	≥ 1 hour 58 minutes prior to ramp start

[4] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

Example of Timing Requirements for WECC



A. Introduction

1. **Title:** **Implementation of Interchange**

2. **Number:** **INT-009-1**

3. **Purpose:** To ensure that the implementation of Interchange between Source and Sink Balancing Authorities is coordinated by an Interchange Authority such that the Balancing Authorities implement the Interchange exactly as agreed upon in the Interchange confirmation process.

4. **Applicability**

   4.1. Balancing Authority.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.

C. Measures

M1. The Balancing Authority shall provide evidence that Implemented Interchange matches Confirmed Interchange as submitted by the Interchange Authority.

M2. Evidence shall demonstrate that the Interchange was implemented in the Balancing Authority's Area Control Error (ACE) equation, or the system that calculates the ACE equation. Evidence may be on a net basis or an individual Interchange basis.

M3. Balancing Authorities that are interconnected with a direct current tie shall demonstrate that the Interchange was implemented in the ACE equation or modeled as an equivalent generator/load within its area.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Regional Reliability Organization.

   1.2. Compliance Monitoring Period and Reset Time Frame

   The Performance-Reset Period shall be twelve months from the last noncompliance to Requirement 1.

   1.3. Data Retention

   The Balancing Authority and Interchange Authority shall each keep 90 days of historical data. The Compliance Monitor shall keep audit records for a minimum of three calendar years.

   1.4. Additional Compliance Information

   Each Balancing Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

   Subsequent to the initial compliance review, compliance may be:

   1.4.1 Verified by audit at least once every three years.

1.4.2 Verified by spot checks in years between audits.

1.4.3 Verified by annual audits of non-compliant Balancing Authorities, until compliance is demonstrated.

1.4.4 Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

The Balancing Authorities shall make the following available for inspection by the Compliance Monitor upon request:

1.4.5 For compliance audits and spot checks, relevant data and system log records for the audit period which indicate a Balancing Authority implemented all instances of the Interchange Authority's communication under R1 concerning the implementation of a Confirmed Interchange. The Compliance Monitor may request up to a three month period of historical data ending with the date the request is received by the Balancing Authority

1.4.6 For specific complaints, only those data and system log records associated with the specific Interchange event contained in the complaint which indicates a Balancing Authority implemented the Interchange Authority's communication under R1 concerning the implementation of the Confirmed Interchange for that specific Interchange.

2. Levels of Non-Compliance

2.1. Level 1: One occurrence[1] of not implementing a Confirmed Interchange as described in R1.

2.2. Level 2: Two occurrences[1] of not implementing a Confirmed Interchange as described in R1.

2.3. Level 3: Three occurrences[1] of not implementing a Confirmed Interchange as described in R1.

2.4. Level 4: Four or more occurrences[1] of not implementing a Confirmed Interchange as described in R1 or no evidence provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

[1] This does not include instances of not implementing due to extenuating circumstances approved by the Compliance Monitor.

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Standards Announcement

Project 2008-12 Coordinate Interchange Standards
INT-006-4, INT-009-2, INT-011-1, and Definitions

Final Ballots now open through December 20, 2013

Now Available

Final ballots for **INT-006-4, INT-009-2, INT-011-1, and 11 definitions** are now open through **8 p.m. Eastern on Friday, December 20, 2013.**

INT-004-3, INT-010-2, and the definitions of Request for Interchange and Arranged Interchange required substantive changes based on stakeholder feedback. On December 9, 2013, they were posted for a 45-day comment period. Additional ballots for the two standards, two definitions, and non-binding polls of the Violation Risk Factors and Violation Severity Levels associated with the two standards will be conducted January 10-22, 2014.

Background information for this project can be found on the project page.

Instructions for Commenting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps

Voting results for the standards and definitions will be posted and announced after the ballot windows close. If approved, they will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

The Standards Processes Manual 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 Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
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Standards Announcement

Project 2008-12 Coordinate Interchange Standards INT-006-4, INT-009-2, INT-011-1, and Definitions

Final Ballot Results

Now Available

Final ballots for **INT-006-4, INT-009-2, INT-011-1, and 11 definitions** concluded at **8 p.m. Eastern on Friday, December 20, 2013.**

The standards and definitions achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

	Ballot
	Quorum /Approval
INT-006-4	85.07% / 80.77%
INT-009-2	85.07% / 72.86%
INT-011-1	84.78% / 72.91%
11 Definitions	85.37% / 83.60%

Background information for this project can be found on the project page.

Next Steps

The standards and definitions will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

A 45-day formal comment period for **INT-004-3, INT-010-2 and the revised definitions for Request for Interchange and Arranged Interchange** is now open through 8 p.m. Eastern on Friday, January 22, 2014. Additional ballots for the two standards, two definitions, and non-binding polls of the Violation Risk Factors and Violation Severity Levels associated with the two standards will be conducted January 10-22, 2014.

Standards Development Process

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Ballot Results	
Ballot Name:	Project 2008-12 INT-006-4
Ballot Period:	12/10/2013 - 12/20/2013
Ballot Type:	Final Ballot
Total # Votes:	285
Total Ballot Pool:	335
Quorum:	**85.07 % The Quorum has been reached**
Weighted Segment Vote:	80.77 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	90	1	44	0.786	12	0.214	0	20	14
2 - Segment 2	8	0.6	6	0.6	0	0	0	2	0
3 - Segment 3	79	1	40	0.816	9	0.184	0	20	10
4 - Segment 4	24	1	10	0.714	4	0.286	0	7	3
5 - Segment 5	72	1	32	0.78	9	0.22	0	15	16
6 - Segment 6	49	1	25	0.735	9	0.265	0	9	6
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.1	1	0.1	0	0	0	1	0
10 - Segment 10	7	0.6	5	0.5	1	0.1	0	1	0
Totals	**335**	**6.6**	**166**	**5.331**	**44**	**1.269**	**0**	**75**	**50**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke		
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	

1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	

3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Florida Power Corporation	Lee Schuster	Negative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS

4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Negative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY

				COMMENTS
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Negative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	

6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Ballot Results	
Ballot Name:	Project 2008-12 INT-009-2
Ballot Period:	12/10/2013 - 12/20/2013
Ballot Type:	Final Ballot
Total # Votes:	285
Total Ballot Pool:	335
Quorum:	**85.07 % The Quorum has been reached**
Weighted Segment Vote:	72.86 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	90	1	38	0.704	16	0.296	0	22	14
2 - Segment 2	8	0.6	6	0.6	0	0	0	2	0
3 - Segment 3	79	1	34	0.694	15	0.306	0	20	10
4 - Segment 4	24	1	7	0.5	7	0.5	0	7	3
5 - Segment 5	72	1	26	0.65	14	0.35	0	16	16
6 - Segment 6	49	1	22	0.688	10	0.313	0	11	6
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.1	1	0.1	0	0	0	1	0
10 - Segment 10	7	0.5	5	0.5	0	0	0	2	0
Totals	**335**	**6.5**	**142**	**4.736**	**62**	**1.765**	**0**	**81**	**50**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke		
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	

1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Affirmative	

3	Colorado Springs Utilities	Charles Morgan	Negative	
3	ComEd	John Bee	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Negative	COMMENT RECEIVED
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	

3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Negative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	

5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Abstain	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	

6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Southern California Edison Company	Joseph T Marone	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2008-12 INT-011-1
Ballot Period:	12/10/2013 - 12/20/2013
Ballot Type:	Final Ballot
Total # Votes:	284
Total Ballot Pool:	335
Quorum:	**84.78 % The Quorum has been reached**
Weighted Segment Vote:	72.91 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	90	1	42	0.712	17	0.288	0	16	15
2 - Segment 2	8	0.6	6	0.6	0	0	0	2	0
3 - Segment 3	79	1	35	0.673	17	0.327	0	17	10
4 - Segment 4	24	1	10	0.588	7	0.412	0	4	3
5 - Segment 5	72	1	28	0.636	16	0.364	0	12	16
6 - Segment 6	49	1	25	0.676	12	0.324	0	6	6
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.2	1	0.1	1	0.1	0	0	0
10 - Segment 10	7	0.6	6	0.6	0	0	0	1	0
Totals	**335**	**6.7**	**156**	**4.885**	**70**	**1.815**	**0**	**58**	**51**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke		
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Negative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke		
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY

				COMMENTS
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	Central Lincoln PUD	Steve Alexanderson	Negative	COMMENT RECEIVED
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY

				COMMENTS
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	
3	Colorado Springs Utilities	Charles Morgan	Negative	
3	ComEd	John Bee	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Negative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	SUPPORTS THIRD PARTY COMMENTS

3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	
5	City of Tallahassee	Karen Webb	Negative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Negative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh		

5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	

6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Negative	SUPPORTS THIRD PARTY COMMENTS
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

404.446.2560 voice : 404.446.2595 fax
Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2008-12 Def and IP
Ballot Period:	12/10/2013 - 12/20/2013
Ballot Type:	Final Ballot
Total # Votes:	286
Total Ballot Pool:	335
Quorum:	**85.37 % The Quorum has been reached**
Weighted Segment Vote:	83.60 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	90	1	42	0.808	10	0.192	0	27	11
2 - Segment 2	8	0.7	6	0.6	1	0.1	0	1	0
3 - Segment 3	79	1	34	0.85	6	0.15	0	27	12
4 - Segment 4	24	1	9	0.818	2	0.182	0	10	3
5 - Segment 5	72	1	25	0.758	8	0.242	0	23	16
6 - Segment 6	49	1	23	0.767	7	0.233	0	12	7
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	3	0.3	0	0	0	1	0
9 - Segment 9	2	0.1	1	0.1	0	0	0	1	0
10 - Segment 10	7	0.6	6	0.6	0	0	0	1	0
Totals	**335**	**6.7**	**149**	**5.601**	**34**	**1.099**	**0**	**103**	**49**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Lakeland Electric	Larry E Watt	Negative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Abstain	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY

				COMMENTS
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Clewiston	Lynne Mila		
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	

3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas		
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
	Constellation Energy Control & Dispatch,			

4	L.L.C.	Margaret Powell	Negative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Amerenue	Sam Dwyer	Abstain	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Negative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer	Abstain	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Abstain	
5	NextEra Energy	Allen D Schriver	Negative	
				SUPPORTS

5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	THIRD PARTY COMMENTS
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Abstain	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	

6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Abstain	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Montana Consumer Counsel	Larry P. Nordell	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
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6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).
8. Third draft of standard posted for 45 day formal comment period with parallel initial ballot (September 30 – November 15, 2013).
9. Fourth draft of standard posted for formal comment period with parallel initial ballot (December 9, 2013 – January 22, 2014).

Description of Current Draft

This is the fifth draft of the proposed standard and is being posted for final ballot. This draft includes modifications based on comments submitted by stakeholders.

Anticipated Actions	Anticipated Date
Final ballot	January 2014
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become

effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Dynamic Transfers**
2. **Number:** INT-004-3
3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Purchasing-Selling Entity
5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of Dynamic Transfers.

   - R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement now includes Pseudo-Ties.
   - R2 is modified from INT-004-2 to separate the triggers for the review of the Dynamic Transfer and when a modification is required for the Dynamic Transfer.
   - R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo-Ties ensure that all entities involved are aware of the Dynamic Transfer and agree that the various responsibilities associated with the dynamic transfer have been agreed upon.
   - R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
   - The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any Dynamic Transfer.

B. Requirements and Measures

R1. Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1] Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about

Rationale for R1: This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

[1] Please refer to the timing tables of INT-006-4.

the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]

M1. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-Tie. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the Purchasing-Selling Entity shall have evidence such as Interchange Distribution Calculator model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)

R2. The Purchasing-Selling Entity that submits a Request for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

> Rationale for R2: This requirement does not preclude tags from being updated at any time. The requirement specifies conditions under which the tag must be updated.

2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.

2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.

2.3. The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

M2. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation met the criteria in Requirement R2, Parts 2.1- 2.3. (R2)

R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Purchasing-Selling Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Purchasing-Selling Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a Purchasing-Selling Entity or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.

R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-Ties are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as Scheduled Interchange. The obligations of the entities involved in each type of Dynamic Transfer are dependent on the type of Dynamic Transfer selected. These guidelines provide items that should be considered when determining which type of Dynamic Transfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a Dynamic Transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
    - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services FERC OATT Schedules 3–6 and other ancillary services as	Attaining BA	Native BA

required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE Frequency Bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their Frequency Bias Setting to account for the Frequency Bias characteristics of the loads and/or resources being assigned between BA(s) by the Pseudo-Tie	The Attaining BA should include the Load from its Dynamic Schedule as a part of its forecast load to set Frequency Bias requirement. The Native BA should change its Load used to set Frequency Bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

The unique handling of curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
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6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).
8. Third draft of standard posted for 45 day formal comment period with parallel initial ballot (September 30 – November 15, 2013).
9. ~~8.~~9. Fourth draft of standard posted for 45 day formal comment period with parallel initial ballot (December 9, 2013 – January 22, 2014).

Description of Current Draft

This is the ~~fourth~~ fifth draft of the proposed standard and is being posted for ~~stakeholder comments and an additio~~final ballot. This draft includes ~~the~~ modifications based on comments submitted by stakeholders.

Anticipated Actions	Anticipated Date
~~45-day Formal Comment Period with Parallel Initial Ballot~~	~~December 2013-January 2014~~
~~Recirculation~~ Final ballot	January 2014
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Dynamic Transfers**
2. **Number:** INT-004-3
3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.
4. **Applicability:**

   4.1. Balancing Authority

   4.2. Purchasing-Selling Entity
5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of D~~d~~ynamic ~~t~~Transfers.

   - R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement now includes Pseudo-Ties.
   - R2 is modified from INT-004-2 to separate the triggers for the review of the D~~d~~ynamic ~~t~~Transfer and when a modification is required for the D~~d~~ynamic T~~t~~ransfer.
   - R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo-Ties ensure that all entities involved are aware of the D~~d~~ynamic ~~t~~Transfer and agree that the various responsibilities associated with the dynamic transfer have been agreed upon.
   - R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
   - The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any D~~d~~ynamic ~~t~~Transfer.

B. Requirements and Measures

R1. Each -Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1] Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or

Rationale for R1: This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

[1] Please refer to the timing tables of INT-006-4.

Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]

M1. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-Tie. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the Purchasing-Selling Entity shall have evidence such as Interchange Distribution Calculator model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)

R2. The Purchasing-Selling Entity that submits a Request ~~F~~for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

Rationale for R2: This requirement does not preclude tags from being updated at any time. The requirement specifies conditions under which the tag must be updated.

2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.

2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.

2.3. The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

M2. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation met the criteria in Requirement R2, Parts 2.1- 2.3. (R2)

R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

Rationale for R3: This Requirement is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. Transparency of all Pseudo-Ties ensures proper modeling by all impacted entities. This requirement will become effective when the NAESB Electric Industry Registry (EIR) accepts Pseudo-Tie registrations. Requirements for Pseudo-Tie registration will be defined in NAESB business practices which are developed through open industry practices. All existing Pseudo-Ties will need to be registered and verified. This will be addressed in the Project 2008-12 implementation plan.

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Purchasing-Selling Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Purchasing-Selling Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a Purchasing-Selling Entity or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.~~,~~
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.

R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority ~~did not~~ implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-Ties are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as Scheduled Interchange. The obligations of the entities involved in each type of D~~d~~ynamic T~~t~~ransfer are dependent on the type of D~~d~~ynamic T~~t~~ransfer selected. These guidelines provide items that should be considered when determining which type of D~~d~~ynamic T~~t~~ransfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a D~~d~~ynamic T~~t~~ransfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
    - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services FERC OATT Schedules 3–6 and other ancillary services as	Attaining BA	Native BA

required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE Frequency Bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their Frequency Bias S~~s~~etting to account for the F~~f~~requency B~~b~~ias characteristics of the loads and/or resources being assigned between BA(s) by the Pseudo-Tie	The Attaining BA should include the Load from its D~~d~~ynamic ~~s~~Schedule as a part of its forecast load to set F~~f~~requency B~~b~~ias requirement. The Native BA should change its Load used to set Frequency Bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

The unique handling of curtailments of Dynamic Transfers is described ~~I~~in NERC's Dynamic Transfer Reference Guidelines, Version 2.~~, it describes unique handling of curtailments of dynamic transfers.~~

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule S~~s~~ignal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as D~~d~~ynamic ~~t~~Transfer S~~s~~ignals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe ~~that~~ when Curtailments (typically communicated through e-Tags) of D~~d~~ynamic T~~t~~ransfers ~~occur, they~~ require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Project 2008-12: Coordinate Interchange Standards

VRF and VSL Justifications for INT-004-3

VRF and VSL Justifications – INT-004-3, R1	
Proposed VRF	Lower
NERC VRF Discussion	Dynamic Schedules or Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring Arranged Interchanges is submitted, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.

VRF and VSL Justifications – INT-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to submit a Request for Interchange.

VRF and VSL Justifications – INT-004-3, R2	
Proposed VRF	Lower
NERC VRF Discussion	Dynamic Schedules or Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-004-2, R2, which deals with updating tagging information and is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1-2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-004-3, R2	
Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to ensure the Confirmed Interchange or Pseudo-Tie was updated for the next available scheduling hour or future hours.

VRF and VSL Justifications – INT-004-3, R3	
Proposed VRF	Lower
NERC VRF Discussion	Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring Arranged Interchanges is submitted, is assigned a Lower VRF. Also, INT-004-3, R1, which deals with submittal of RFI, is also assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority implemented or operated a Pseudo-Tie for that was not included in the NAESB Electric Industry Registry publication.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	This guideline is not applicable because this is a new requirement.

VRF and VSL Justifications – INT-004-3, R3	
the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to implement or operate a Pseudo-Tie in the NASEB Electric Industry Registry publication.

Project 2008-12: Coordinate Interchange Standards

VRF and VSL Justifications for INT-004-3

VRF and VSL Justifications – INT-004-3, R1	
Proposed VRF	Lower
NERC VRF Discussion	Dynamic Schedules or Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring Arranged Interchanges is submitted, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.;

VRF and VSL Justifications – INT-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to submit a Request for Interchange.

VRF and VSL Justifications – INT-004-3, R2	
Proposed VRF	Lower
NERC VRF Discussion	Dynamic Schedules or Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-004-2, R2, which deals with updating tagging information and is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1-2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-004-3, R2	
Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to ensure the Confirmed Interchange or Pseudo-Tie was updated for the next available scheduling hour or future hours.

VRF and VSL Justifications – INT-004-3, R3	
Proposed VRF	Lower
NERC VRF Discussion	Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring Arranged Interchanges is submitted, is assigned a Lower VRF. Also, INT-004-3, R1, which deals with submittal of RFI, is also assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority ~~did not~~ implemented or operated a Pseudo-Tie for that was not included in the NAESB Electric Industry Registry publication.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	This guideline is not applicable because this is a new requirement.

VRF and VSL Justifications – INT-004-3, R3	
the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to implement or operate a Pseudo-Tie in the NASEB Electric Industry Registry publication.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).
8. Third draft of standard posted for 45 day formal comment period with parallel initial ballot (September 30 – November 15, 2013).
9. Fourth draft of standard posted for 45-day formal comment period with parallel additional ballot (December 9, 2013- January 22, 2014)

Description of Current Draft

This is the fifth draft of the proposed standard and is being posted for final ballot. This draft includes the modifications based on comments submitted by stakeholders.

Anticipated Actions	Anticipated Date
Final ballot	January 2014
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Board of Trustees Adoption	New
1	March 16, 2007	FERC Approval	New
2	TBD	Board of Trustees Adoption	Revised under Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Interchange Initiation and Modification for Reliability**
2. **Number:** **INT-010-2**
3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.
4. **Applicability:**

   4.1. Balancing Authority
5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to replace "request for Arranged Interchange" with the correct term "Request for Interchange." A rationale was developed to clarify use of the term "energy sharing agreement" for this requirement.
   - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.

B. Requirements and Measures

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

> Rationale for R1: This requirement was originally revised to replace the term "Request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted an RFI per Requirement R1. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was submitted within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a Request for Interchange was submitted reflecting that Interchange Schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, and R3, for the most recent three calendar months plus the current month.
- If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Request for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that scheduled Interchange.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule Curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the Curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
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8. Third draft of standard posted for 45 day formal comment period with parallel initial ballot (September 30 – November 15, 2013).
9. Fourth draft of standard posted for 45-day formal comment period with parallel additional ballot (December 9, 2013- January 22, 2014)

Description of Current Draft

This is the ~~fourth~~ fifth draft of the proposed standard and is being posted for ~~stakeholder comments and an additiona~~final ballot. This draft includes the modifications based on comments submitted by stakeholders.

Anticipated Actions	Anticipated Date
~~45-day Formal Comment Period with Parallel Additional Ballot~~	~~December 2013 – January 2014~~
~~Recirculation~~ Final ballot	January 2014
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006~~TBD~~	Board of Trustees Adoption	New
1	March 16, 2007	FERC Approval	New
2	TBD	Board of Trustees Adoption	Revised under Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Interchange Initiation and Modification for Reliability**

2. **Number:** **INT-010-2**

3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.

4. **Applicability:**

   4.1. Balancing Authority

5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to replace "request for Arranged Interchange" with the correct term "Request for Interchange". A rationale was developed to clarify use of the term "energy sharing agreement" for this requirement.
   - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.

B. Requirements and Measures

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

> Rationale for R1: This requirement was originally revised to replace the term "Request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted an RFI per Requirement R1. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was submitted within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange S~~s~~chedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a Request for~~F~~ Interchange was submitted reflecting that Interchange S~~s~~chedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority ~~and Transmission Service provider~~ shall ~~each~~ keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, and R3, for the most recent three calendar months plus the current month.
- If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request ~~F~~for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Request for~~F~~ Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of thate scheduled Interchange.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule Curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the Curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Project 2008-12: Coordinate Interchange Standards

VRF and VSL Justifications for INT-010-2

VRF and VSL Justifications – INT-010-2, R1	
Proposed VRF	Lower
NERC VRF Discussion	After the fact submittal of a Request For Interchange (RFI) will not impact transmission congestion but may impact the ability to adequately assess transmission conditions for future hours. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-010-1, R1, which deals with submitting Arranged Interchange after the fact, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
Proposed Moderate VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for

VRF and VSL Justifications – INT-010-2, R1	
	Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
Proposed High VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
Proposed Severe VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for this requirement mirror existing VSLs for this revised requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single	Guideline 2a: Not applicable. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.

VRF and VSL Justifications – INT-010-2, R1	
Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to ensure that the Request for Interchange was submitted, or for an RFI that was submitted with a start time more than 60 minutes following the resource loss.

VRF and VSL Justifications – INT-010-2, R2	
Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures that modified RFI is submitted for any Interchange that was modified at the direction of a Reliability Coordinator. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.

VRF and VSL Justifications – INT-010-2, R2	
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-010-1, R2, which deals with submitting a modified Arrange Interchange, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.

VRF and VSL Justifications – INT-010-2, R2	
Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of ensuring that a Reliability Adjustment Arranged Interchange reflecting the modification was submitted within 60 minutes following the start of the modification.

VRF and VSL Justifications – INT-010-2, R3	
Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures that modified RFI is submitted for any Interchange that was modified at the direction of a Reliability Coordinator. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-010-1, R3, which deals with submitting a modified Arrange Interchange, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.

VRF and VSL Justifications – INT-010-2, R3	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority did not ensure that a Request for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that scheduled Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-010-2, R3	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of not ensuring that a RFI was submitted within 60 minutes following the start of the scheduled Interchange.

Project 2008-12: Coordinate Interchange Standards

VRF and VSL Justifications for INT-010-2

VRF and VSL Justifications – INT-010-2, R1	
Proposed VRF	Lower
NERC VRF Discussion	After the fact submittal of a Request For Interchange (RFI) will not impact transmission congestion but may impact the ability to adequately assess transmission conditions for future hours. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-010-1, R1, which deals with submitting Arranged Interchange after the fact, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
Proposed Moderate VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for

VRF and VSL Justifications – INT-010-2, R1	
	Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
Proposed High VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
Proposed Severe VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request ~~F~~for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for this requirement mirror existing VSLs for this revised requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single	Guideline 2a: Not applicable. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.

VRF and VSL Justifications – INT-010-2, R1	
Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to ensure that the Request for Interchange was submitted, or for an RFI that was submitted with a start time more than 60 minutes following the resource loss.

VRF and VSL Justifications – INT-010-2, R2	
Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures that modified RFI is submitted for any Interchange that was modified at the direction of a Reliability Coordinator. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.

VRF and VSL Justifications – INT-010-2, R2	
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-010-1, R2, which deals with submitting a modified Arrange Interchange, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.

VRF and VSL Justifications – INT-010-2, R2	
Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of ensuring that a Reliability Adjustment Arranged Interchange reflecting the modification was submitted within 60 minutes following the start of the modification.

VRF and VSL Justifications – INT-010-2, R3	
Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures that modified RFI is submitted for any Interchange that was modified at the direction of a Reliability Coordinator. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-010-1, R3, which deals with submitting a modified Arrange Interchange, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.

VRF and VSL Justifications – INT-010-2, R3	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority did not ensure that a Request ~~F~~for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that~~e~~ scheduled Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned “Severe.” Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-010-2, R3	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of not ensuring that a RFI was submitted within 60 minutes following the start of the scheduled Interchange.

Proposed Definitions for the NERC Glossary of Terms

Project 2008-12: Coordinate Interchange Standards

The Coordinate Interchange Standards Drafting (CISDT) received comments on the proposed set of definitions to be revised or added to the NERC Glossary of Terms. The CISDT made substantive revisions to two of the definitions based on these comments. These revised definitions are streamlined and are an improvement to the previously proposed definitions. These two defined terms are being posted for a 45-day comment period with ballot being conducted over the last 10 days of the comment period.

Revisions to Defined Terms in the NERC Glossary

- **Request for Interchange** - A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.

- **Arranged Interchange** - The state where a Request for Interchange (initial or revised) has been submitted for approval.

Standards Announcement

Project 2008-12 Coordinate Interchange Standards
Two Definitions

Additional Ballot Results

Now Available

An additional ballot of two definitions (**Request for Interchange** and **Arranged Interchange**) associated with Project 2008-12 Coordinate Interchange Standards concluded at **8 p.m. Eastern on Wednesday, January 29, 2014.**

The definitions achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

Ballot Results
Quorum /Approval
76.12% / 92.17%

Background information for this project can be found on the project page.

Next Steps

The definitions will be posted for a final ballot. If they are approved by the ballot pool, they will be submitted to the NERC Board of Trustees for adoptions and then filed with applicable government authorities.

Standards Development Process

The Standard Processes Manual 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 Wendy Muller (via email),
Standards Development Administrator, or at 404-446-2560.

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Standards Announcement

Project 2008-12 Coordinate Interchange Standards INT-004-3 and INT-010-2

Final Ballots Now Open Through February 5, 2014

Now Available

Final ballots for **INT-004-3 (Dynamic Transfers) and INT-010-2 (Interchange Initiation and Modification for Reliability)**, are now open through **8 p.m. Eastern on Wednesday, February 5, 2014.**

The Coordinate Interchange Standard Drafting Team has reviewed the comments from the comment period and ballots that ended on January 22, 2014 and adopted a number of suggestions, including minor clarifications to language in Requirements, VSLs, and the Guideline and Technical Basis of the standards. None of the changes are substantive. A complete list of the changes to each standard is provided in the Consideration of Comments posted on the project page.

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps

Voting results for the standard will be posted and announced after the ballot window closes. If approved, the standard will be submitted to the Board of Trustees for adoption.

Standards Development Process

The Standards Processes Manual 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 Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2008-12 Coordinate Interchange Standards

Final Ballot Results

Now Available

Final ballots for **INT-004-3 (Dynamic Transfers) and INT-010-2 (Interchange Initiation and Modification for Reliability)** concluded at **8 p.m. Eastern on Wednesday, February 5, 2014**.

The standards achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

	Ballot Results
	Quorum /Approval
INT-004-3	83.88% / 83.44%
INT-010-2	83.58% / 91.51%

Background information for this project can be found on the project page.

Next Steps
The NERC Board of Trustees adopted the standards on February 6, 2014. The standards will be filed with applicable regulatory authorities.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
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Atlanta, GA 30326
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Ballot Results	
Ballot Name:	Project 2008-12 INT-004-3
Ballot Period:	1/27/2014 - 2/5/2014
Ballot Type:	**Final Ballot**
Total # Votes:	281
Total Ballot Pool:	335
Quorum:	83.88 % The Quorum has been reached
Weighted Segment Vote:	83.44 %
Ballot Results:	A quorum was reached and there were sufficient affirmative votes for approval

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	90	1	54	0.806	13	0.194	0	12	11
2 - Segment 2	8	0.5	4	0.4	1	0.1	0	2	1
3 - Segment 3	79	1	45	0.849	8	0.151	0	12	14
4 - Segment 4	24	1	14	0.875	2	0.125	0	4	4
5 - Segment 5	72	1	37	0.771	11	0.229	0	8	16
6 - Segment 6	49	1	31	0.756	10	0.244	0	3	5
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.2	2	0.2	0	0	0	0	2
9 - Segment 9	2	0.1	1	0.1	0	0	0	1	0

10 - Segment 10	7	0.5	5	0.5	0	0	0	1	1
Totals	**335**	**6.3**	**193**	**5.257**	**45**	**1.043**	**0**	**43**	**54**

Individual Ballot Pool Results				
Segment	**Organization**	**Member**	**Ballot**	**NERC Notes**
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dayton Power & Light Co.	Hertzel Shamash	Negative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Georgia Transmission Corporation	Jason Snodgrass		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	

1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	COMMENT RECEIVED - Alice Ireland
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		

3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	

3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Abstain	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	

5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	COMMENT RECEIVED
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	

6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Florida Power & Light Co.	Silvia P Mitchell	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS- Alice Ireland (Murdock), Xcel Energy
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy
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Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2008-12 INT-010-2
Ballot Period:	1/27/2014 - 2/5/2014
Ballot Type:	**Final Ballot**
Total # Votes:	280
Total Ballot Pool:	335
Quorum:	**83.58 % The Quorum has been reached**
Weighted Segment Vote:	91.51 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	90	1	55	0.887	7	0.113	0	17	11
2 - Segment 2	8	0.5	4	0.4	1	0.1	0	2	1
3 - Segment 3	79	1	50	0.98	1	0.02	0	15	13
4 - Segment 4	24	1	11	0.917	1	0.083	0	7	5
5 - Segment 5	72	1	38	0.864	6	0.136	0	11	17
6 - Segment 6	49	1	33	0.917	3	0.083	0	8	5
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.2	2	0.2	0	0	0	0	2
9 - Segment 9	2	0.1	1	0.1	0	0	0	1	0

10 - Segment 10	7	0.5	5	0.5	0	0	0	1	1
Totals	**335**	**6.3**	**199**	**5.765**	**19**	**0.535**	**0**	**62**	**55**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	CPS Energy	Richard Castrejana		
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Georgia Transmission Corporation	Jason Snodgrass		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Affirmative	

3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Abstain	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities	Tim Beyrle		

	Commission			
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Abstain	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Abstain	
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
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5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
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5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
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5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	

5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Northern Indiana Public Service Co.	Huston Ferguson		
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Abstain	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Abstain	
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Florida Power & Light Co.	Silvia P Mitchell	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	

6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

404.446.2560 voice : 404.446.2595 fax
Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Standards Announcement

Project 2008-12 Coordinate Interchange Standards
Two Definitions

Final Ballot Results

Now Available

A final ballot of two definitions (**Request for Interchange** and **Arranged Interchange**) associated with Project 2008-12 Coordinate Interchange Standards concluded at **8 p.m. Eastern on Monday, February 10, 2014.**

The definitions achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

Ballot Results
Quorum /Approval
81.79% / 90.12%

Background information for this project can be found on the project page.

Next Steps

The NERC Board of Trustees conditionally adopted the definitions, subject to final ballot approval, on February 6, 2014. The definitions, along with all of the standards and other definitions that are part of Project 2008-12, will be filed with applicable regulatory authorities.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2008-12 Def and IP Final Ball
Ballot Period:	1/31/2014 - 2/10/2014
Ballot Type:	**Final Ballot**
Total # Votes:	274
Total Ballot Pool:	335
Quorum:	**81.79 % The Quorum has been reached**
Weighted Segment Vote:	90.12 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	90	1	57	0.891	7	0.109	0	14	12
2 - Segment 2	8	0.5	5	0.5	0	0	0	2	1
3 - Segment 3	79	1	51	0.944	3	0.056	0	10	15
4 - Segment 4	24	1	13	0.929	1	0.071	0	5	5
5 - Segment 5	72	1	36	0.837	7	0.163	0	11	18
6 - Segment 6	49	1	30	0.857	5	0.143	0	5	9
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	2	0.1	1	0.1	0	0	0	1	0

10 - Segment 10	7	0.6	5	0.5	1	0.1	0	1	0
Totals	**335**	**6.5**	**201**	**5.858**	**24**	**0.642**	**0**	**49**	**61**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Abstain	

1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	

3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila		
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik		
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	COMMENT RECEIVED
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Sohrab A Yari		
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	

3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Abstain	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	American Wind Energy Association	Michael Goggin		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb		
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Lakeland Electric	James M Howard	Negative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	

5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
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5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
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5	Southern Company Generation	William D Shultz	Affirmative	
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5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
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6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	

6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Lincoln Electric System	Eric Ruskamp		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis		
6	Powerex Corp.	Gordon Dobson-Mack	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Abstain	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Montana Consumer Counsel	Larry P. Nordell		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Account Log-In/Register

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed on (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).
8. Third draft of standard posted for 45 day formal comment period with parallel initial ballot (September 30 – November 15, 2013).
9. Fourth draft of standard posted for formal comment period with parallel initial ballot (December 9, 2013 – January 22, 2014).

Description of Current Draft

This is the fifth draft of the proposed standard and is being posted for final ballot. This draft includes modifications based on comments submitted by stakeholders.

Anticipated Actions	Anticipated Date
Final ballot	January 2014
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become

effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Dynamic Transfers**
2. **Number:** INT-004-3
3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Purchasing-Selling Entity
5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of Dynamic Transfers.

   - R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement now includes Pseudo-Ties.
   - R2 is modified from INT-004-2 to separate the triggers for the review of the Dynamic Transfer and when a modification is required for the Dynamic Transfer.
   - R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo-Ties ensure that all entities involved are aware of the Dynamic Transfer and agree that the various responsibilities associated with the dynamic transfer have been agreed upon.
   - R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
   - The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any Dynamic Transfer.

B. Requirements and Measures

R1. Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1] Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about

> Rationale for R1: This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

[1] Please refer to the timing tables of INT-006-4.

the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]

M1. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-Tie. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the Purchasing-Selling Entity shall have evidence such as Interchange Distribution Calculator model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)

R2. The Purchasing-Selling Entity that submits a Request for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

> Rationale for R2: This requirement does not preclude tags from being updated at any time. The requirement specifies conditions under which the tag must be updated.

2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.

2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.

2.3. The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

M2. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation met the criteria in Requirement R2, Parts 2.1- 2.3. (R2)

R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support congestion management procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Purchasing-Selling Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Purchasing-Selling Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a Purchasing-Selling Entity or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.

R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-Ties are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as Scheduled Interchange. The obligations of the entities involved in each type of Dynamic Transfer are dependent on the type of Dynamic Transfer selected. These guidelines provide items that should be considered when determining which type of Dynamic Transfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a Dynamic Transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
    - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services FERC OATT Schedules 3–6 and other ancillary services as	Attaining BA	Native BA

required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE Frequency Bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their Frequency Bias Setting to account for the Frequency Bias characteristics of the loads and/or resources being assigned between BA(s) by the Pseudo-Tie	The Attaining BA should include the Load from its Dynamic Schedule as a part of its forecast load to set Frequency Bias requirement. The Native BA should change its Load used to set Frequency Bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

The unique handling of curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Application Guidelines

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

Description of Current Draft

This is the third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	September – October 2013
Recirculation ballot	December 2013
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1.0	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2.0	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3.0	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3.0	July 1, 2010	Approved by FERC	Revised
4.0	TBD	Adopted by the NERC Board Of Trustees	Revised in Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Evaluation of Interchange Transactions**
2. **Number:** INT-006-4
3. **Purpose:** To ensure that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented.
4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Service Provider
5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-006-4 continues to be the reliability assessment of Interchange Transactions prior to their implementation.

   The content of INT-006-4 has been revised and expanded in the following manner:

   - R1 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Balancing Authority must deny the transition.
   - R2 was created by revising R1 from INT-006-3. This requirement ensures that Transmission Service Providers involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Transmission Service Provider must deny the transition.
   - R3 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange.
   - R4 was created by moving and revising R1 from INT-007-1, which has been retired as part of the project. This requirement lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange.
   - R5 was created by moving and revising R1 from INT-008-3, which has been retired as part of the project. This requirement lists the entities to which a Sink Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.
   - Attachment 1 timing tables for WECC were modified to address scheduling on a 15 minute basis.

Requirements and Measures

R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

> Rationale for R1: Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing Authority must deny an Arranged Interchange, but Balancing Authorities may deny for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

M1. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R1)

> Rationale for R2: TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in Requirement R1, Part 2.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

R2. Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M2. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each Arranged Interchange or emergency Arranged Interchange within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R2)

R3. The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

3.1. If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.

M3. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request and, if applicable, communicated denial to the Reliability Coordinator no more than 10 minutes after the denial. (R3)

R4. Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

- It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

M4. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that, under the conditions in R4, it did not transition an Arranged Interchange to Confirmed Interchange. (R4)

R5. For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

5.1. The Source Balancing Authority,

5.2. Each Intermediate Balancing Authority,

5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,

5.4. Each Transmission Service Provider included in the Arranged Interchange, and

5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

M5. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it notified the entities of the on-time Confirmed Interchange such that the notification was delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D. (R5)

B. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R3, R4, and R5 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R2 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange. OR The Scheduling Path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.
R2	Operations Planning,	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Same-day Operations, Real-time Operations					Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
R3	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
R4	Operations Planning, Same-day Operations,	Lower	N/A	N/A	N/A	The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-time Operations					an Arranged Interchange to Confirmed Interchange.
R5	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Sink Balancing Authority did not notify all of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.	The Sink Balancing Authority did not notify any of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange. OR The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify one or more of the entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Attachment 1 – Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [1] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[2]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[2]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time		≤ 20 minutes from Arranged Interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start

[1] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[2] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

[redacted]

Attachment 1 – Timing Tables

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<10 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is not the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 5 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of	On-time		≤ 6 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[4] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
the hour					
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 7 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 8 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 9 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time		By 12:00 PPT of day the Arranged Interchange was received		≥ 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing Interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - All reliability entities involved in the Arranged Interchange are valid.
    - Generation source and Load sink are defined.
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
    - Distribute notification as each entity approves or denies an Arranged Interchange.
    - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
    - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

  - Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
  - Receive distribution of Arranged Interchange
  - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
  - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
  - Submit a request to modify Interchange

- While Interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
  - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
  - How to notify others that it is activating the plan
  - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
  - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
  - Delegation of approval rights and proxy actions, if such approaches will be used.
  - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
  - Personnel plans for short-term and extended periods.
  - Training of personnel in the use of the plan.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).

Description of Current Draft

This is the third draft of the proposed standard and is being posted for stakeholder comments and an initial ballot. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	September – October 2013
Recirculation ballot	December2013
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	TBD	Adopted by the NERC Board of Trustees	Revised under Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Implementation of Interchange**
2. **Number:** **INT-009-2**
3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.
4. **Applicability:**

    4.1. Balancing Authority.

5. **Background:**

    This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.

    The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term "Composite Confirmed Interchange" has been introduced.

    The content of INT-009-2 has been revised and expanded in the following manner:

    - R1 was combined with INT-003-3 R1 and modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.
    - R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Actual Net Interchange term for their ACE controls.
    - R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls a high-voltage direct current tie coordinates the Confirmed Interchange.

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

Rationale for R2: R12.3 of BAL-005-2b addresses common metering for Dynamic Schedules and Pseudo-Ties but not their implementation into ACE. Requirement R2 is parallel to R10 of BAL-005-2b which only addresses Dynamic Schedules. Presently, there is a gap in the BAL standards that this requirement fills for Pseudo-Ties.

M2. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). (R2)

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2 and R3 for the most recent 3 months plus the current month.

If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange.
R2	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process).
R3	Real-time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (July 2, 2008 through July 31, 2008).
2. Revised SAR and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).
4. SDT appointed (February 12, 2009).
5. First draft of proposed standard posted (November 10, 2009).
6. Project became inactive until February, 2013.
7. Second draft of standard posted for 30 day informal comment period (July 25-August 23, 2013).
8. Third draft of standard posted for 45 day formal comment period with parallel initial ballot (September 30 – November 15, 2013).
9. Fourth draft of standard posted for 45-day formal comment period with parallel additional ballot (December 9, 2013- January 22, 2014)

Description of Current Draft

This is the fifth draft of the proposed standard and is being posted for final ballot. This draft includes the modifications based on comments submitted by stakeholders.

Anticipated Actions	Anticipated Date
Final ballot	January 2014
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Board of Trustees Adoption	New
1	March 16, 2007	FERC Approval	New
2	TBD	Board of Trustees Adoption	Revised under Project 2008-12

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Interchange Initiation and Modification for Reliability**
2. **Number:** **INT-010-2**
3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.
4. **Applicability:**

   4.1. Balancing Authority
5. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to replace "request for Arranged Interchange" with the correct term "Request for Interchange." A rationale was developed to clarify use of the term "energy sharing agreement" for this requirement.
   - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.

B. Requirements and Measures

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

Rationale for R1: This requirement was originally revised to replace the term "Request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted an RFI per Requirement R1. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was submitted within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a Request for Interchange was submitted reflecting that Interchange Schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, and R3, for the most recent three calendar months plus the current month.
- If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Request for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that scheduled Interchange.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule Curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the Curtailment.

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

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Development Steps Completed

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Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	September - October 2013
Recirculation ballot	December 2013
BOT adoption	February 2014
File standard with regulatory authorities.	February 2014

Effective Dates

The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Adopted by the NERC Board of Trustees	New standard developed

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Intra-Balancing Authority Transaction Identification**
2. **Number:** **INT-011-1**
3. **Purpose:** To ensure that transfers within a Balancing Authority Area using Point to Point Transmission Service are communicated and accounted for in congestion management procedures.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Load-Serving Entities
5. **Background:**

   This standard was created in response to a FERC directive in Order 693, paragraph 817: *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

   The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

B. Requirements and Measures

R1. Each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange unless the information about intra-Balancing Authority transfers is included in congestion management procedure(s) via an alternate method. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations]*

M1. Each Load-Serving Entity subject to R1 shall have evidence, such as dated and time-stamped electronic records, documentation of congestion management procedures, or other similar evidence, that a Request for Interchange was submitted for each Point to Point Transmission Service intra-Balancing Authority transfer subject to R1 or that each intra-Balancing Authority transfer subject to R1 was accounted for in congestion management procedure(s) via an alternate method. (R1)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Load-Serving Entity shall keep data or evidence to show compliance with R1 for the most recent three months plus the current month unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	*Operations Planning, Same-day Operations*	*Lower*	N/A	N/A	N/A	The Load-Serving Entity used Point to Point Transmission Service for an intra-Balancing Authority Area transfer, and did not submit a Request for Interchange for an intra-Balancing Authority transfer that is not included in congestion management procedure(s) via an alternate method.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Implementation Plan

Project 2008-12: Coordinate Interchange Standards

Requested Approvals

- INT-004-3 — Dynamic Transfers
- INT-006-4 — Evaluation of Interchange Transactions
- INT-009-2 — Implementation of Interchange
- INT-010-2 — Interchange Initiation and Modification for Reliability
- INT-011-1 — Intra-Balancing Authority Transaction Identification

Requested Retirements

- INT-001-3 Interchange Information
- INT-003-3 Interchange Transaction Implementation
- INT-004-2 Dynamic Interchange Transaction Modifications
- INT-005-3 Interchange Authority Distributes Arranged Interchange
- INT-006-3 Response to Interchange Authority
- INT-007-1 Interchange Confirmation
- INT-008-3 Interchange Authority Distributes Status
- INT-009-1 Implementation of Interchange
- INT-010-1 Interchange Coordination Exemptions

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

- **Dynamic Interchange Schedule or Dynamic Schedule:** A time-varying energy transfer that is updated in Real-time and included in the Net Interchange Schedule term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Pseudo-Tie:** A time-varying energy transfer that is updated in Real-time and included in the Net Interchange Actual term (NI_A) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

- **Request for Interchange** - A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.
- **Arranged Interchange** - The state where a Request for Interchange (initial or revised) has been submitted for approval.
- **Confirmed Interchange** - The state where no party has denied and all required parties have approved the Arranged Interchange.
- **Adjacent Balancing Authority** - A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
- **Intermediate Balancing Authority** - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
- **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.
- **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.
- **Operational Planning Analysis:** An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Proposed additional Defined Terms to be added to the NERC Glossary

- **Reliability Adjustment Arranged Interchange** – A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
- **Composite Confirmed Interchange –** The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
- **Attaining Balancing Authority:** A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.
- **Native Balancing Area:** A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

Background

The standards were developed under Project 2008-12, Coordinate Interchange Standards. The drafting team revised the existing approved standards and grouped the requirements in distinct groupings within each standard. The drafting team developed a new standard, INT-011-1, Intra-Balancing Authority Transaction Identification, in response to a FERC directive in Order 693, paragraph 817:

> *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

The proposed revision to the definition of Operational Planning Analysis addresses a FERC Order 693 directive:

> *866. Accordingly, the Commission approves Reliability Standard INT-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.*

The Reliability Coordinator and Transmission Operator are required to perform an Operational Planning Analysis in existing IRO-008-1, Requirement R1 and in TOP-002-3, Requirement R1 which was filed with FERC on April 16, 2013. By including the term "Interchange" explicitly in the definition, the drafting team has addressed the directive.

Applicable Entities

- Balancing Authority
- Transmission Service Provider
- Load-Serving Entities

Effective Date

First day of the second calendar quarter beyond the date each standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date each standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Standards for Retirement

Midnight of the day immediately prior to the Effective Date of the new standards in the particular jurisdiction in which the new standards are becoming effective.

Implementation Plan for Definitions

Entities shall use all proposed definitions when implementing any requirements within the new standards which use the defined term(s).

Implementation Plan for INT-004-3, Requirement R3

Requirement R3 is intended to ensure that a Pseudo-Tie is properly established prior to its implementation. A request to revise the NAESB Electric Industry Registry has already been submitted for implementation. This requirement will become effective on the first calendar day two calendar quarters after the NAESB Electric Industry Registry is able to accept Pseudo-Tie registrations. All existing and future Pseudo-Ties are to be registered in the NAESB Electric Industry Registry.

Proposed Definitions for the NERC Glossary of Terms

Project 2008-12: Coordinate Interchange Standards

The Coordinate Interchange Standards Drafting (CISDT) received comments on the proposed set of definitions to be revised or added to the NERC Glossary of Terms. The CISDT made minor clarifying edits of several of the definitions based on these comments. These proposed defined terms are being posted for a final ballot.

Revisions to Defined Terms in the NERC Glossary

- **Request for Interchange -** A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.
- **Arranged Interchange** - The state where a Request for Interchange (initial or revised) has been submitted for approval.
- **Dynamic Interchange Schedule or Dynamic Schedule:** A time-varying energy transfer that is updated in Real-time and included in the Scheduled Net Interchange (NI_S) term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Pseudo-Tie:** A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NI_A) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).
- **Confirmed Interchange** - The state where no party has denied and all required parties have approved the Arranged Interchange.
- **Adjacent Balancing Authority** - A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
- **Intermediate Balancing Authority** - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
- **Sink Balancing Authority** - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.
- **Source Balancing Authority** - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.

- **Operational Planning Analysis:** An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Proposed additional Defined Terms to be added to the NERC Glossary

- **Reliability Adjustment Arranged Interchange** – A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
- **Composite Confirmed Interchange –** The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
- **Attaining Balancing Authority:** A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.
- **Native Balancing Authority:** A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

Project 2008-12: Coordinate Interchange Standards

VRF and VSL Justifications for INT-004-3

VRF and VSL Justifications – INT-004-3, R1	
Proposed VRF	Lower
NERC VRF Discussion	Dynamic Schedules or Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring Arranged Interchanges is submitted, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.

VRF and VSL Justifications – INT-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to submit a Request for Interchange.

VRF and VSL Justifications – INT-004-3, R2	
Proposed VRF	Lower
NERC VRF Discussion	Dynamic Schedules or Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-004-2, R2, which deals with updating tagging information and is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1-2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-004-3, R2	
Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to ensure the Confirmed Interchange or Pseudo-Tie was updated for the next available scheduling hour or future hours.

VRF and VSL Justifications – INT-004-3, R3	
Proposed VRF	Lower
NERC VRF Discussion	Pseudo-Ties may impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring Arranged Interchanges is submitted, is assigned a Lower VRF. Also, INT-004-3, R1, which deals with submittal of RFI, is also assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority implemented or operated a Pseudo-Tie for that was not included in the NAESB Electric Industry Registry publication.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	This guideline is not applicable because this is a new requirement.

VRF and VSL Justifications – INT-004-3, R3	
the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to implement or operate a Pseudo-Tie in the NASEB Electric Industry Registry publication.

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VRF and VSL Justifications for INT-006-4

VRF and VSL Justifications – INT-006-4, R1	
Proposed VRF	Lower
NERC VRF Discussion	Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-006-3, R1, which deals with responding to on-time RFI, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR

VRF and VSL Justifications – INT-006-4, R1	
	The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange. OR The Scheduling Path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-006-4, R1	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to take action on an on-time Arranged Interchange or an emergency Arranged Interchange, or for failing to deny an Arranged Interchange under certain circumstances.

VRF and VSL Justifications – INT-006-4, R2	
Proposed VRF	Lower
NERC VRF Discussion	Transmission Service Providers must take action on a received Arranged Interchange within a certain time frame. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-006-3, R1, which deals with responding to on-time RFI, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – INT-006-4, R2	
Proposed High VSL	N/A
Proposed Severe VSL	The Transmission Service Provider receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned “Severe.” Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-006-4, R2	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to take action on an on-time Arranged Interchange or an emergency Arranged Interchange, or for failing to deny an Arranged Interchange or curtail Confirmed Interchange under certain circumstances.

VRF and VSL Justifications – INT-006-4, R3	
Proposed VRF	Lower
NERC VRF Discussion	Source or Sink Balancing Authorities receiving a Reliability Adjustment Arranged Interchange need to approve or deny it prior to the expiration of the reliability assessment period defined in the timing requirements. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-006-3, R1, which deals with approving or denying Arranged Interchange is submitted, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A

VRF and VSL Justifications – INT-006-4, R3	
Proposed Moderate VSL	N/A
Proposed High VSL	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.
Proposed Severe VSL	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: Not applicable. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-006-4, R3	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to act on a Reliability Adjustment Arranged Interchange within a certain time frame, or for failing to communicate a denial to the Reliability Coordinator within 10 minutes of the denial.

VRF and VSL Justifications – INT-006-4, R4	
Proposed VRF	Lower
NERC VRF Discussion	Balancing Authorities should not transition Arranged Interchange to Confirmed Interchange under certain conditions. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-007-13, R1, which deals with ensuring Arranged Interchanges is valid before transitioning to Confirmed Interchange, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A

VRF and VSL Justifications – INT-006-4, R4	
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning an Arranged Interchange to Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of	The VSL is assigned for a single instance of transitioning an Arranged Interchange to Confirmed Interchange under certain circumstances under which an Interchange should not be transitioned.

VRF and VSL Justifications – INT-006-4, R4	
Violations	

VRF and VSL Justifications – INT-006-4, R5	
Proposed VRF	Lower
NERC VRF Discussion	Distributing information regarding whether an Arranged Interchange was transitioned to Confirmed Interchange is necessary to ensure that everyone has the same information regarding the transactions. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-008-3, R1, which deals with distributing information regarding whether an Arranged Interchange was transitioned to Confirmed Interchange, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	The Sink Balancing Authority did not distribute notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to all of the entities listed in Requirement R5 Parts 5.1-5.5.

VRF and VSL Justifications – INT-006-4, R5	
Proposed Severe VSL	The Sink Balancing Authority did not notify any of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange. OR The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify one or more of the entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs assigned to this requirement do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: Not applicable. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4	The VSL is assigned for a single instance of failing to distribute

VRF and VSL Justifications – INT-006-4, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	notification of whether an Arranged Interchange was transitioned to Confirmed Interchange to specific entities.

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VRF and VSL Justifications for INT-009-2

VRF and VSL Justifications – INT-009-2, R1	
Proposed VRF	Medium
NERC VRF Discussion	Agreement between Balancing Authorities regarding the magnitude and direction of Composite Confirmed Interchange is necessary to ensure that each balancing Authority is controlling their generation for the proper amount of Interchange. If the values are not agreed to, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite

VRF and VSL Justifications – INT-009-2, R1	
	Confirmed Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, excluding Dynamic Schedules and including any interchange as directed by a Reliability Coordinator per INT-010-2 not yet captured in the Composite Confirmed Interchange, for that hour.

VRF and VSL Justifications – INT-009-2, R2	
Proposed VRF	Medium
NERC VRF Discussion	Agreement between Balancing Authorities regarding the source to be used for a Pseudo-Tie is necessary to ensure that each balancing Authority is controlling their generation for the proper amount of Interchange associated with the Pseudo-Tie. If the values are not agreed to, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual (NI_A) term of their respective control ACE (or alternate control process).
FERC VSL G1 Violation Severity Level Assignments Should Not	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-009-2, R2	
Have the Unintended Consequence of Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual term of their respective control ACE (or alternate control process).

VRF and VSL Justifications – INT-009-2, R3	
Proposed VRF	Medium
NERC VRF Discussion	Coordination of Interchange across HVDC is necessary to ensure that the Facility is operated within its limits and that each Balancing Authority is controlling to a correct Interchange value. If the interchange is not appropriately accounted for, the capability of and/or the ability to effectively monitor and control the bulk electric system could be affected, but it is unlikely that such a violation would lead to instability, separation, or cascading failures.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-003-3, R1, which deals with confirming and agreeing to Interchange values prior to implementation, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.

VRF and VSL Justifications – INT-009-2, R3	
the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned “Severe.” Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie..

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VRF and VSL Justifications for INT-010-2

VRF and VSL Justifications – INT-010-2, R1	
Proposed VRF	Lower
NERC VRF Discussion	After the fact submittal of a Request For Interchange (RFI) will not impact transmission congestion but may impact the ability to adequately assess transmission conditions for future hours. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-010-1, R1, which deals with submitting Arranged Interchange after the fact, is assigned a Lower VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
Proposed Moderate VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for

VRF and VSL Justifications – INT-010-2, R1	
	Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
Proposed High VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
Proposed Severe VSL	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs for this requirement mirror existing VSLs for this revised requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single	Guideline 2a: Not applicable. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.

VRF and VSL Justifications – INT-010-2, R1	
Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to ensure that the Request for Interchange was submitted, or for an RFI that was submitted with a start time more than 60 minutes following the resource loss.

VRF and VSL Justifications – INT-010-2, R2	
Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures that modified RFI is submitted for any Interchange that was modified at the direction of a Reliability Coordinator. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.

VRF and VSL Justifications – INT-010-2, R2	
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-010-1, R2, which deals with submitting a modified Arrange Interchange, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority did not ensure that a Reliability Adjustment Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.

VRF and VSL Justifications – INT-010-2, R2	
Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of ensuring that a Reliability Adjustment Arranged Interchange reflecting the modification was submitted within 60 minutes following the start of the modification.

VRF and VSL Justifications – INT-010-2, R3	
Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures that modified RFI is submitted for any Interchange that was modified at the direction of a Reliability Coordinator. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* This Requirement is a revision of comparable INT-010-1, R3, which deals with submitting a modified Arrange Interchange, is assigned a Lower VRFs.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.

VRF and VSL Justifications – INT-010-2, R3	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Sink Balancing Authority did not ensure that a Request for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that scheduled Interchange.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is assigned a single Severe VSL and does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned “Severe.” Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – INT-010-2, R3	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of not ensuring that a RFI was submitted within 60 minutes following the start of the scheduled Interchange.

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VRF and VSL Justifications for INT-011-1

The drafting team will complete the following table, providing of analysis and justification for each VRF and VSL, for each requirement in INT-011-1—Intra-Balancing Authority Transaction Identification

VRF and VSL Justifications – INT-011-1, R1	
Proposed VRF	Lower
NERC VRF Discussion	Transfers within a Balancing Authority Area can potentially impact transmission congestion, and thus the transfers need to be communicated and accounted for in congestion management processes. A single violation of this Requirement would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This guideline is not applicable, as the requirement does not have any sub-requirements.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable INT-001-3, R1, which deals with ensuring that Arranged Interchange is submitted. This requirement is assigned a Lower VRF
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A

VRF and VSL Justifications – INT-011-1, R1	
Proposed Severe VSL	The Load-Serving Entity used Point to Point Transmission Service for an intra-Balancing Authority Area transfer, and did not submit a Request for Interchange for an intra-Balancing Authority transfer that is not included in congestion management procedure(s) via an alternate method.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This guideline is not applicable because this is a new standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is binary, and the single VSL is appropriately assigned "Severe." Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly violated if a Request for Interchange is not submitted or the transfer is not included in congestion management procedure(s) via an alternate method.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	The VSL is assigned for a single instance of failing to submit a Request for Interchange or include the transfer in congestion management procedure(s) via an alternate method.

VRF and VSL Justifications – INT-011-1, R1	
on A Single Violation, Not on A Cumulative Number of Violations	

Project 2008-12 - Coordinate Interchange Standards

Mapping Document

Project Purpose

The purpose of Project 2008-12 is to revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange. The drafting team also addressed the Interchange Subcommittee concerns related to the dynamic Transfers and Pseudo-ties and addressed previously identified stakeholder comments and applicable directives from Order 693. These issues and directives include defining communications on reloading interchange transactions due to different operational conditions and to bringing the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for: **R1.1.** All Dynamic Schedules at the expected average MW profile for each hour.	Revised and Moved into INT-004-3	**INT-004-3:** **R1.** Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1]

[1] Please refer to the timing tables of INT-006-4.

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Independent Expert Review recommendation: Retain Requirement.		Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*] [1] Please refer to the timing tables of INT-006-4. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.
R2. The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority: **R2.1.** If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator. **R2.2.** For each bilateral Inadvertent	Retired	The CI SDT believes that this requirement is no longer necessary for reliability. Since the proposed INT-009-2 R1 makes it clear that the Net Scheduled Interchange term in the control equation can only include Confirmed Interchange as agreed to between Balancing Authorities, this by definition requires that an Arranged Interchange be created in order to implement the schedules listed in

Standard: INT-001-3, Interchange Information		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Interchange payback. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		R2.1 and R2.2. From a reliability perspective, it is unimportant who creates these Arranged interchanges – only that they be created and confirmed prior to being entered into the control equation. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. **R1.1.** The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including:	Revised and Moved into INT-009-2	**INT-009-2:** R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1.1.1. Interchange Schedule start and end time. **R1.1.2.** Energy profile. **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. Independent Expert Review recommendation: Retain Requirement.		in the Composite Confirmed Interchange, is: [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority. R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Net Interchange Actual (NI_A) term of their respective control ACE (or alternate control process). [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations] R3. Each Balancing Authority in whose area the HVDC tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the HVDC tie. [Violation Risk Factor: Medium] [Time Horizon: Real Time Operations, Operations Planning]

Standard: INT-003-3, Interchange Transaction Implementation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority. Independent Expert Review recommendation: Retire	Retired	The CI SDT believes that at a minimum, this requirement does not belong in the "Dynamic Schedules" standard. However, for several reasons, the CI SDT further believes that this specific requirement is no longer required: • It mandates a practice (releasing of E-Tag limits) that is process related. • The practice is already addressed in related NAESB standards (WEQ-004 Appendix B - E-Tag Actions).

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
per P81 criteria. A guideline exists in the functional specification for electronic tagging.		• Use of a limit (and the associated release of that limit) is only one particular way to address curtailments. Other ways exist that could be used in lieu of this approach. The reliability standard should not mandate a single approach when others may suffice. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.
R2. The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occurs: **R2.1.** The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +10%. **R2.2.** The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated	Revised	**INT-004-3** **R2.** The Purchasing-Selling Entity that submits a Request for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same Day Operations, Real Time Operations] **2.1.** For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and

Standard: INT-004-2, Dynamic Interchange Transaction Modifications		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
on the tag by more than +25 megawatt-hours. **R2.3.** A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		that deviation is expected to persist. **2.2.** For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist. **2.3.** The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange. CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have the RFI updated for a Dynamic Schedule or Pseudo-Tie that is significantly different than the original schedule. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis.

Standard: INT-005-3, Interchange Authority Distributes Arranged Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the time period defined in the timing requirements tables in this standard, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange. **R1.1.** When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Retired	The CISDT is proposing retirement of this requirement. The entities to receive the transaction are included today in the eTag specification, Section 3.6.1.1.1. The timing requirement for the distribution of tags is removed from this standard, as they are currently included and expected to remain in the NAESB documentation. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the reliability assessment period defined in the timing requirements tables in this standard, Column B, the Balancing Authority and Transmission Service Provider shall respond to each On-time Request for Interchange (RFI), and to each Emergency RFI and Reliability Adjustment RFI from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange. **R1.1.** Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to: **R1.1.1.** Energy profile (ability to support the magnitude of the Interchange). **R1.1.2.** Ramp (ability of generation maneuverability to accommodate). **R1.1.3.** Scheduling path (proper connectivity of Adjacent Balancing Authorities). **R1.2.** Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the	Revised	R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange. 1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid. R2. Each Transmission Service Provider shall approve

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid. CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that this distribution requirement may currently drive how software performs this function. However, if that software were not present, this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the

Standard: INT-006-3, Response to Interchange Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		interchange to occur.

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following: **R1.1.** Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate). **R1.2.** All reliability entities involved in the Arranged Interchange are currently in the NERC registry. **R1.3.** The following are defined: **R1.3.1.** Generation source and load sink. **R1.3.2.** Megawatt profile. **R1.3.3.** Ramp start and stop times. **R1.3.4.** Interchange duration. **R1.4.** Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.	Retired, Revisions made to defined term used in various INT standards to clarify reliability objective	R1.1, R1.2 and R1.3 ensure the data submitted on the interchange is valid. This activity occurs in software validation and is not appropriate for a reliability standard; these items are included in the Technical Basis and Guidelines section of INT-006. Interchange that does not meet these criteria would not be an Arranged Interchange. R1.4. is addressed in the proposed revision to the definition of Confirmed Interchange: *The state where no party has denied and all required parties have approved the Arranged Interchange.* INT-006-4, Requirement R4 also specifies conditions under which the BA shall not transition to Confirmed Interchange: R4. Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: [Violation Risk Factor: Lower] [Time

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		Horizon: Operations Planning, Same-day Operations, Real-time Operations] • It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition. • It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition. • It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

Standard: INT-007-1, Interchange Confirmation		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs.

Standard: INT-008-3, Interchange Authority Distributes Status		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange. **R1.1.** For Confirmed Interchange, the Interchange Authority shall also communicate: **R1.1.1.** Start and stop times, ramps, and megawatt profile to Balancing Authorities. **R1.1.2.** Necessary Interchange information to NERC-identified reliability analysis services. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised and moved into INT-006-4	**INT-006-4:** R5. Each Sink Balancing Authority shall distribute all notifications of whether an Arranged Interchange was transitioned to Confirmed Interchange to the following entities, and notifications of on-time Confirmed Interchange shall be distributed such that they are delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations] 5.1. The Source Balancing Authority, 5.2. Each Intermediate Balancing Authority, 5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange, 5.4. Each Transmission Service Provider included in the Arranged Interchange, and 5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

Standard: INT-008-3, Interchange Authority Distributes Status		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that this distribution requirement may currently drive how software performs this function. However, if that software were not present, this requirement clearly directs who needs to receive the results of the evaluations that were performed in order for the interchange to occur.

Standard: INT-009-1, Implementation of Interchange		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Combined with INT-003-3, Requirement R1	**INT-009-2** **R1.** Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] 1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and 1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority. CISDT Consideration of Independent Expert Review recommendation: The CISDT concurs that a separate requirement is not necessary. This requirement was combined with INT-003-3, Requirement R1.

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange is required. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised	**INT-010-2:** **R1.** The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R2. For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.	Revised	**INT-010-2:** **R2.** Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis
R3. For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent	Revised	**INT-010-2:**

Standard: INT-010-1, Interchange Coordination Exemptions		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event. Independent Expert Review recommendation: Retire per P81 criteria. A guideline exists in the functional specification for electronic tagging.		**R3.** Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*] CISDT Consideration of Independent Expert Review recommendation: In the absence of clear industry consensus supporting the Independent Expert Review recommendation to retire this requirement, the CISDT believes that there is a reliability need to have an RFI submitted for this type of Interchange. This will allow the IDC and WITT Tool to have more accurate interchange data for reliability analysis

Consideration of Issues and Directives

Project 2008-12 Coordinate Interchange Standards | December 2013

Issue or Directive	Source	Consideration of Issue or Directive
817. In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.	FERC Order 693, Paragraph 817	INT-011-1, R1 addresses the directive in FERC Order 693, Paragraph 817. While the Commission asked that the ERO modify INT-001-2 to address the directive, the Project 2008-12 has proposed INT-001-2 for retirement and thus, it is most appropriate to create a new standard that addresses the directive. The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and INT-011-1 ensures that these transfers are communicated and accounted for in congestion management procedures. If a transfer within a Balancing Authority Area is submitted as a Request for Interchange or otherwise accounted for in congestion management procedures, it can be evaluated and processed comparable to a Request for Interchange that crosses Balancing Authority Areas. **R1.** Each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange

Issue or Directive	Source	Consideration of Issue or Directive
		unless the information about intra-Balancing Authority transfers is included in congestion management procedure(s) via an alternate method. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations]*
819. With respect to Santa Clara's position that LSEs should be applicable entities under the Reliability Standard, the Commission notes that in situations where a LSE is securing energy from outside the balancing authority to supply its end-use customers, it would function as a purchasing-selling entity, as defined in the NERC glossary, and would be included in the NERC registry on that basis. This interpretation flows from the language of the Reliability Standards, and the Commission does not perceive any ambiguity in this connection. Nevertheless, the Commission directs the ERO to consider Santa Clara's comments, and whether some more explicit language would be useful, in the course of modifying INT-001-2 through the Reliability Standards development process.	FERC Order 693, Paragraph 819	The CISDT has retained the Purchasing Selling Entity the proposed INT standards and believes that general industry consensus supports the Purchasing-Selling Entity being the appropriate applicable entity.
843. As explained in the NOPR, while the Commission	FERC Order	The CISDT has added all compliance elements to the

Issue or Directive	Source	Consideration of Issue or Directive
has identified concerns with regard to INT-004-1, this proposed Reliability Standard serves an important purpose by setting thresholds on changes in dynamic schedules for which modified interchange data must be submitted. Further, the Requirements set forth in INT-004-1 are sufficiently clear and objective to provide guidance for compliance. Accordingly, the Commission approves Reliability Standard INT-004-1 as mandatory and enforceable. In addition, the Commission directs the ERO to consider adding these Measures and Levels of Non-Compliance to the Reliability Standard.	693, Paragraph 843	standard, including VRFs, VSLs and Time Horizons. NOTE: FERC retired this directive on November 21, 2013 in Docket No. RM13-8-000.
848. The Commission is satisfied that the Requirements of INT-005-1 are appropriate to ensure that interchange information is distributed timely and available for reliability assessment. Accordingly, the Commission approves Reliability Standard INT-005-1 as mandatory and enforceable. In addition, the Commission directs the ERO to consider adding additional Measures and Levels of Non-Compliance to the Reliability Standard.	FERC Order 693, Paragraph 848	The CISDT has added all compliance elements to the standard, including VRFs, VSLs and Time Horizons. NOTE: FERC retired this directive in an order issued on November 21, 2013 in Docket No. RM13-8-000.
866. Accordingly, the Commission approves Reliability	FERC Order	See separate document regarding an equally efficient and

Issue or Directive	Source	Consideration of Issue or Directive
Standard INT-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation. We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.	693, Paragraph 866	effective method of addressing this directive. (Order 693 Paragraph 866 - CISDT White Paper)
871. APPA agrees with the Commission that INT-008-1 is sufficient for approval as a mandatory and enforceable Reliability Standard, subject to NERC's plans for the registration of entities as interchange authorities. It suggests that NERC should clarify which reliability entities have the responsibility for ensuring	FERC Order 693, Paragraphs 871 and 872	The Interchange Authority entity has been replaced with the Sink Balancing Authority throughout the INT standards.

Issue or Directive	Source	Consideration of Issue or Directive
that interchange information is coordinated between the source and sink balancing authorities before implementing the Reliability Standard. APPA also states that NERC should modify this Reliability Standard to make clear what entities it in fact would apply to. 872. The Commission approves Reliability Standard INT-008-1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that a source and sink balancing authority will serve as the interchange authority until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process. Finally, we direct the ERO to consider APPA's suggestions in the Reliability Standards development process.		
874. APPA agrees with the Commission that INT-009-1 is sufficient for approval as a mandatory and enforceable Reliability Standard, subject to NERC's plans for the registration of entities as interchange authorities. It suggests that NERC modify its Functional	FERC Order 693, Paragraphs 874 and 875	The Interchange Authority entity has been replaced with the Sink Balancing Authority throughout the INT standards.

Issue or Directive	Source	Consideration of Issue or Directive
Model to clarify which reliability entities have the responsibility for ensuring proper implementation of interchange transactions that have received reliability assessments. APPA also suggests that NERC modify this Reliability Standard to make clear what entities it in fact would apply to. 875. The Commission approves Reliability Standard INT-009-1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that a source and sink balancing authority will serve as the interchange authority until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process. Finally, we direct the ERO to consider APPA's suggestions concerning this Reliability Standard in the Reliability Standards development process.		
879. Northern Indiana supports the Commission's interpretation of INT-010-1, but it requests that the Reliability Standard be modified to explicitly state that it does not include actual IROL violations.	FERC Order 693, Paragraphs 879, 880 and	The CISDT has reviewed the comments of Northern Indiana and ISO-NE with respect to possible revisions to INT-010-1. The CSIDT has proposed a new defined term: **Reliability Adjustment Arranged Interchange –** A request to

Issue or Directive	Source	Consideration of Issue or Directive
880. ISO-NE supports Commission approval of INT-010-1, but does not share the Commission's concerns regarding the initiation or modification of interchange schedules to address SOL or IROL violations. It states that interchange schedules can in certain circumstances provide an additional effective tool to help prevent an SOL and IROL violation. While ISO-NE recognizes that other tools may in certain circumstances be more effective, it states that this neither diminishes the value nor precludes the use of the tools contained in INT-010-1. ISO-NE also notes that section 2.4 of INT-010-1, which describes Level 4 Non-Compliance, should be edited to state that "[t]here shall be a level four non-compliance. . . " instead of "[t]here shall be a level three non-compliance. . . ." 887. Accordingly, the Commission approves Reliability Standard INT-010-1 as mandatory and enforceable. In addition, we adopt the interpretation set forth in the NOPR that these current or imminent reliability-related reasons do not include actual IROL violations, since they require immediate control actions so that the system can be returned to a secure operating state as soon as possible and no longer than 30 minutes after a	887	modify a Confirmed Interchange or Implemented Interchange for reliability purposes. This proposed term is used in one requirement: R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [Violation Risk Factor: Lower] [Time Horizon: Real Time Operations] The CISDT notes that submitting a revised tag within 60 minutes ensures that modification of interchange will not be used to relieve an IROL as most IROLs have to be mitigated within 30 minutes or a lesser value of T_v. The CISDT does not believe that additional specificity regarding actual IROL violations is necessary for this standard.

Issue or Directive	Source	Consideration of Issue or Directive
reliability-related system interruption – a period that is much shorter than the time that is expected to be required for new or modified transactions to be implemented. Finally, we direct the ERO to consider Northern Indiana and ISO-NE's suggestions in the Reliability Standards development process.		
On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: • Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define "Non-Asset Owning LSEs" as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset.	FERC's December 20, 2007 and April 4, 2008 Orders	The LSE entity is incorporated into the INT standards, but the requirements apply regardless of whether the LSE is an asset owning LSE or not.

Issue or Directive	Source	Consideration of Issue or Directive
• Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. Specifically, the following description has been incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that		

Issue or Directive	Source	Consideration of Issue or Directive
includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: • FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) • NERC's March 4, 2008		

Issue or Directive	Source	Consideration of Issue or Directive
(http://www.nerc.com/files/FinalFiledLSE3408.pdf), • FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and • NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.		
NAESB Standards Review Subcommittee as input to the Reliability Standards Development Plan: 2010-2012: NAESB requests that NERC engage in coordination with them as needed on this project as it relates to item 3.a.viii in the NAESB WEQ 2009 Annual Plan.	NAESB Standards Review Subcommittee	The NERC JESS has members on the CISDT and they are coordinating with NAESB on this project.
The SDT review the definitions of the following terms and coordinate with NAESB so that the definition of each term is consistent between NERC and NAESB: Interchange Schedule Interchange Transaction	NERC/NAESB Coordination	The CISDT has proposed revisions to some of these terms and members will coordinate revisions to them on the NAESB Glossary.

Issue or Directive	Source	Consideration of Issue or Directive
Interchange Transaction Tag (Tag) Request for Interchange Source BA Sink BA		
These terms reflect the continued use of the IA, and be consistent (not identical) between NERC and NAESB. Request for Interchange Arranged Interchange Confirmed Interchange	NERC/NAESB Coordination	The CISDT has proposed revisions to some of these terms and members will coordinate revisions to them on the NAESB Glossary. These terms have been revised to remove the Interchange Authority and to replace it with Sink Balancing Authority. **Request for Interchange -** A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority. **Arranged Interchange -** The state where a Request for Interchange (initial or revised) has been submitted for approval. **Confirmed Interchange -** The state where no party has denied and all required parties have approved the Arranged

Issue or Directive	Source	Consideration of Issue or Directive
		Interchange.
Changes to the INT standards and IRO standards to support Parallel Flow Visualization. This would include addressing the difference between what is "Interchange" and what is "tagged." Currently, INT standards do not require RFIs for internal transactions; and IRO-006-EAST does not mandate curtailment of internal PTP. NAESB may create interim business practices to support this, so we may have to work with them to retire their standards as ours come into effect.	NAESB	This issue is addressed through INT-011-1 and is related to the FERC Order 693 directive contained in Paragraph 817 above. With INT-011, the term Confirmed Interchange will include “Interchange Transactions” as well as “Intra-BA transfers”. The CISDT will provide input to the Five Year Review Team working on IRO-006-EAST suggesting that they replace the term “Interchange Transactions” with “Confirmed Interchange” to capture the appropriate transactions and flows.
Clarify tagging of reserves (INT-001-1)	Version 0 Team	The CISDT does not believe it is necessary (from a reliability perspective) to tag reserves that are not flowing.
Lack of compliance (INT-001-1)	Version 0 Team	Compliance elements were added to the standard including VRFs, VSLs, and Time Horizons.
Non-compliance based on % (INT-004-1)	Version 0 Team	The VSLs now reflect a single violation of a requirement rather than a percentage.

Issue or Directive	Source	Consideration of Issue or Directive
Onerous to BAs (INT-001-1)	Version 0 Team	The standard has been merged with INT-004. Requirement R2 was retired.
R1 - Too stringent (INT-001-1)	Version 0 Team	Requirement R1 was moved into INT-004-3 and revised **R1.** Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1] Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]
R1 Who tags dynamic schedules? (INT-001-1)	Version 0 Team	This is addressed in INT-004-3, Requirement R1. **R1.** Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie

[1] Please refer to the timing tables of INT-006-4.

Issue or Directive	Source	Consideration of Issue or Directive
		shall ensure that a Request for Interchange is submitted as an on-time[2] Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]
R2.2 60 minute time frame questioned (INT-001-1)	Version 0 Team	Requirement R2.2 was retired from the standard.
R1 & 3 administrative (INT-010-1)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements that are administrative per the guidelines set forth under the Paragraph 81 project.
R1, 1.1, 1.1.2, 1.2 commercial and administrative (INT-003-1)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements

[2] Please refer to the timing tables of INT-006-4.

Issue or Directive	Source	Consideration of Issue or Directive
		that are administrative per the guidelines set forth under the Paragraph 81 project.
R1, 1.1, 1.3, 1.3.1, 1.3.2, 1.3.3, 1.3.4, 1.4 administrative (INT-007-1)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements that are administrative per the guidelines set forth under the Paragraph 81 project.
R1, 1.1, 2, 2.1, 2.2 commercial and administrative (INT-001-1)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements that are administrative per the guidelines set forth under the Paragraph 81 project.
R1.1.1 & 1.1.2 – commercial and administrative (INT-008-2)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements that are administrative per the guidelines set forth under the Paragraph 81 project.
R2, 2.2, 2.3 commercial and administrative (INT-004-1)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements

Issue or Directive	Source	Consideration of Issue or Directive
		that are administrative per the guidelines set forth under the Paragraph 81 project.
R5 administrative (INT-005-2)	VRFs Team	The CISDT has performed a thorough review of the INT standards and have proposed retirement of any requirements that are administrative per the guidelines set forth under the Paragraph 81 project.

Proposed Definitions for the NERC Glossary of Terms

Project 2008-12: Coordinate Interchange Standards

The Coordinate Interchange Standards Drafting (CISDT) proposes revisions to ten (10) defined terms in the NERC Glossary of Terms. The CISDT also proposes four (4) new defined terms to be included in the Glossary. These defined terms are used in the INT family of standards and in a few other standards as discussed below.

Proposed revised definitions (redlined):

Dynamic Interchange Schedule or Dynamic Schedule: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in R~~r~~eal-time and ~~used~~ included in the Net Interchange Schedule term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes). ~~as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.~~

> This defined term was revised to provide clarity that a **Dynamic Schedule** is updated in Real-time and is included in the Net Interchange Schedule term in the affected Balancing Authorities' control ACE equations (or alternate control processes). Dynamic Schedules are commonly used for scheduling jointly owned generation to or from another Balancing Authority Area. The revisions to this defined term align with the NERC's Dynamic Transfer Reference Guidelines, (Version 2). This document states (page85):
>
> > A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between BAs. A dynamic schedule typically does not change a BA's operational responsibility; that is, the native BA continues to exercise operational control over, and provides basic BA services to, the dynamically scheduled resources.
> >
> > Dynamic schedules are to be accounted for as interchange schedules by the source, sink, and contract intermediary BA(s), both in their respective ACE equations, and throughout all of their energy accounting processes. Requirement to incorporate into the contract intermediary BA's ACE is subject to regional procedures.
>
> This defined term is also used in BAL-002-WECC, BAL-003-0.1b and BAL-005-0.2b. BAL-003-0.1b will be superseded by BAL-003-1 when it becomes effective April 1, 2015. This defined term is not used in BAL-003-1. It is also contained in the defined term "Reporting ACE" as part of the NIS (Scheduled Net Interchange) term. The "Reporting ACE" definition has not

been approved by FERC. The revisions to this defined term do not change the intent of the requirements in which it is used. The revisions provide additional clarity for these requirements.

Pseudo-Tie: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in R~~r~~eal-time and included in the Net Interchange Actual (NI_A) term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).~~used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.~~

This defined term was revised to provide clarity that a **Pseudo-Tie** is updated in Real-time and is included in the Net Interchange Actual (NI_A) term in the affected Balancing Authorities' control ACE equations (or alternate control processes). Pseudo-Ties are commonly used as a "virtual" tie line flow in the ACE equation but for which no physical tie or energy metering actually exists. The revisions to this defined term align with the NERC's Dynamic Transfer Reference Guidelines, (Version 2). This document states (page 87):

> Pseudo-ties are often employed to assign generators, loads, or both from the BA to which they are physically connected into a BA that has effective operational control of them. Thus, pseudo-ties often provide for change of BA operational responsibility from the native to the attaining BA and at the same time make the attaining BA provider of BA services. In practice, pseudo-ties may be implemented based upon metered or calculated values. All BAs involved account for the power exchange and associated transmission losses as actual interchange between the BAs, both in their ACE equations and throughout all of their energy accounting processes.

This defined term is also used in BAL-002-WECC, BAL-003-0.1b and BAL-005-0.2b. BAL-003-0.1b will be superseded by BAL-003-1 when it becomes effective April 1, 2015. This defined term is not used in BAL-003-1. The revisions to this defined term do not change the intent of the requirements in which it is used. The revisions provide additional clarity for these requirements.

Request for Interchange (RFI) - A collection of data as defined in the NAESB Business Practice Standards ~~RFI Datasheet, to be~~ submitted ~~to the Interchange Authority~~ for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority or an energy transfer within a single Balancing Authority.

This defined term is also contained in the defined term "Emergency Request for Interchange" and the revisions to this defined term do not change the intent of the "Emergency Request for Interchange". By removing references to the Interchange Authority, this definition is now based solely on NAESB Business Practice Standards and definitions rather than any entity that may be responsible for its application for reliability.

Arranged Interchange - The state where a Request for Interchange (initial or revised) has been submitted for approval. ~~the Interchange Authority has received the Interchange information (initial or revised).~~

This defined term is also in MOD-004-1, R11 and R12; also in the "Confirmed Interchange" definition which is also revised under this project. MOD-004-1 was retired under Project 2012-05. Its requirements were incorporated into MOD-001-2, which passed ballot December 20, 2013. This term is not used in the new standard. By removing references to the Interchange Authority, this definition is now based solely on NAESB Business Practice Standards and definitions rather than any entity that may be responsible for its application for reliability. The revisions to this defined term do not change the intent of the requirements or defined terms in which it is used. The revisions provide additional clarity for these requirements and defined terms.

Confirmed Interchange - The state where no party has denied and all required parties have approved ~~the Interchange Authority has verified~~ the Arranged Interchange.

This defined term is also in definition of "Implemented Interchange". By removing references to the Interchange Authority, this definition is now based solely on NAESB Business Practice Standards and definitions rather than any entity that may be responsible for its application for reliability. The revisions to this defined term do not change the intent of the other defined term in which it is used. The revisions provide additional clarity for that defined term.

The defined terms **Request for Interchange (RFI), Arranged Interchange and Confirmed Interchange** are necessary to define the various stages of creation through implementation of Interchange. These defined terms were revised to better align with industry expectations and NAESB business practices.

Adjacent Balancing Authority - A Balancing Authority Area whose Balancing Authority Area ~~that~~ is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.

This defined term is also BAL-002-1a (Interpretation); BAL-005-0.2b (R9, R14); BAL-006-2 (R2, R3, R4); COM-001-2 R5, R6 (not FERC approved); EOP-001-2.1b (Interpretation); Defined terms "Net Actual Interchange" (contains "Adjacent BA Area"), Net Interchange Schedule" and "Reserve Sharing Group".

Intermediate Balancing Authority - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority. ~~Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.~~

This defined term is also BAL-006-2 but only in the Compliance Monitoring Process section (Section D, item 1.1)

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule. ~~(This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)~~

This defined term is also BAL-002-WECC; BAL-006-2 but only in the Compliance Monitoring Process section (Section D, item 1.1); IRO-006-EAST, R3.3; Definition of "RFI" and WECC term "Contributing Schedule" and "Relief Requirement".

Source Balancing Authority - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule. ~~(This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)~~

This defined term is also BAL-002-WECC; BAL-006-2; IRO-006-EAST-1 (R3.3); Definitions of "Request for Interchange" and the WECC term "Contributing Schedule".

The defined terms **Adjacent Balancing Authority, Intermediate Balancing Authority, Sink Balancing Authority and Source Balancing Authority** are necessary to define the various Balancing Authorities involved in the implementation of Interchange and their relationships with regards to Interchange. These defined terms were revised to better align with industry expectations and NAESB business practices.

Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

This defined term was revised to meet a FERC Order 693 Directive (paragraph 866) and is used in IRO-008-1 - Reliability Coordinator Operational Analyses and Real-time Assessments. Requirement R1 specifies that the Reliability Coordinator must perform an **Operational Planning Analysis**. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider interchange when performing the study. Further, Requirement R2 specifies that the Reliability Coordinator must perform a Real-time Assessment. By explicitly including "Interchange" in the definition of Real-time Assessment, the Reliability Coordinator must consider interchange when performing the study. When the results of either of these studies indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3.

Proposed new definitions:

Reliability Adjustment Arranged Interchange – A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

> The defined term **Reliability Adjustment Arrange Interchange** was developed to accurately reflect the types of Interchange that are adjusted for reliability reasons by a Reliability Coordinator or Transmission Operator. This defined term aligns with industry expectations and NAESB business practices.

Composite Confirmed Interchange – The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.

> The defined term **Composite Confirmed Interchange** was developed to define what is to be included in INT-009-2, Requirement R1 to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities. This defined term aligns with industry expectations and NAESB business practices.

Attaining Balancing Authority: A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.

Native Balancing Authority: A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

> The defined terms **Attaining Balancing Authority and Native Balancing Authority** are necessary to define the various Balancing Authorities involved in the implementation of Dynamic Transfers and their relationships with regards to Dynamic Transfers. These defined terms were developed to align with industry expectations and NAESB business practices.

Proposed Definitions for the NERC Glossary of Terms

Project 2008-12: Coordinate Interchange Standards

The Coordinate Interchange Standards Drafting (CISDT) proposes revisions to ten (10) defined terms in the NERC Glossary of Terms. The CISDT also proposes four (4) new defined terms to be included in the Glossary. These defined terms are used in the INT family of standards and in a few other standards as discussed below.

Proposed revised definitions (redlined):

Dynamic Interchange Schedule or Dynamic Schedule: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in R~~r~~eal-time and ~~used~~ included in the Net Interchange Schedule term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes). ~~as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.~~

This defined term was revised to provide clarity that a **Dynamic Schedule** is updated in Real-time and is included in the Net Interchange Schedule term in the affected Balancing Authorities' control ACE equations (or alternate control processes). Dynamic Schedules are commonly used for scheduling jointly owned generation to or from another Balancing Authority Area. The revisions to this defined term align with the NERC's Dynamic Transfer Reference Guidelines, (Version 2). This document states (page85):

> A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between BAs. A dynamic schedule typically does not change a BA's operational responsibility; that is, the native BA continues to exercise operational control over, and provides basic BA services to, the dynamically scheduled resources.
>
> Dynamic schedules are to be accounted for as interchange schedules by the source, sink, and contract intermediary BA(s), both in their respective ACE equations, and throughout all of their energy accounting processes. Requirement to incorporate into the contract intermediary BA's ACE is subject to regional procedures.

This defined term is also used in BAL-002-WECC, BAL-003-0.1b and BAL-005-0.2b. BAL-003-0.1b will be superseded by BAL-003-1 when it becomes effective April 1, 2015. This defined term is not used in BAL-003-1. It is also contained in the defined term "Reporting ACE" as part of the NIS (Scheduled Net Interchange) term. The "Reporting ACE" definition has not

been approved by FERC. The revisions to this defined term do not change the intent of the requirements in which it is used. The revisions provide additional clarity for these requirements.

Pseudo-Tie: A time-varying energy transfer ~~telemetered reading or value~~ that is updated in R~~r~~eal-time and included in the Net Interchange Actual (NI_A) term in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).~~used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.~~

This defined term was revised to provide clarity that a **Pseudo-Tie** is updated in Real-time and is included in the Net Interchange Actual (NI_A) term in the affected Balancing Authorities' control ACE equations (or alternate control processes). Pseudo-Ties are commonly used as a "virtual" tie line flow in the ACE equation but for which no physical tie or energy metering actually exists. The revisions to this defined term align with the NERC's Dynamic Transfer Reference Guidelines, (Version 2). This document states (page 87):

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This defined term is also used in BAL-002-WECC, BAL-003-0.1b and BAL-005-0.2b. BAL-003-0.1b will be superseded by BAL-003-1 when it becomes effective April 1, 2015. This defined term is not used in BAL-003-1. The revisions to this defined term do not change the intent of the requirements in which it is used. The revisions provide additional clarity for these requirements.

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This defined term is also contained in the defined term "Emergency Request for Interchange" and the revisions to this defined term do not change the intent of the "Emergency Request for Interchange". By removing references to the Interchange Authority, this definition is now based solely on NAESB Business Practice Standards and definitions rather than any entity that may be responsible for its application for reliability.

Arranged Interchange - The state where a Request for Interchange (initial or revised) has been submitted for approval. ~~the Interchange Authority has received the Interchange information (initial or revised).~~

This defined term is also in MOD-004-1, R11 and R12; also in the "Confirmed Interchange" definition which is also revised under this project. MOD-004-1 was retired under Project 2012-05. Its requirements were incorporated into MOD-001-2, which passed ballot December 20, 2013. This term is not used in the new standard. By removing references to the Interchange Authority, this definition is now based solely on NAESB Business Practice Standards and definitions rather than any entity that may be responsible for its application for reliability. The revisions to this defined term do not change the intent of the requirements or defined terms in which it is used. The revisions provide additional clarity for these requirements and defined terms.

Confirmed Interchange - The state where no party has denied and all required parties have approved ~~the Interchange Authority has verified~~ the Arranged Interchange.

This defined term is also in definition of "Implemented Interchange". By removing references to the Interchange Authority, this definition is now based solely on NAESB Business Practice Standards and definitions rather than any entity that may be responsible for its application for reliability. The revisions to this defined term do not change the intent of the other defined term in which it is used. The revisions provide additional clarity for that defined term.

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Intermediate Balancing Authority - A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority. ~~Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.~~

This defined term is also BAL-006-2 but only in the Compliance Monitoring Process section (Section D, item 1.1)

Sink Balancing Authority - The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule. ~~(This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)~~

This defined term is also BAL-002-WECC; BAL-006-2 but only in the Compliance Monitoring Process section (Section D, item 1.1); IRO-006-EAST, R3.3; Definition of "RFI" and WECC term "Contributing Schedule" and "Relief Requirement".

Source Balancing Authority - The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule. ~~(This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)~~

This defined term is also BAL-002-WECC; BAL-006-2; IRO-006-EAST-1 (R3.3); Definitions of "Request for Interchange" and the WECC term "Contributing Schedule".

The defined terms **Adjacent Balancing Authority, Intermediate Balancing Authority, Sink Balancing Authority and Source Balancing Authority** are necessary to define the various Balancing Authorities involved in the implementation of Interchange and their relationships with regards to Interchange. These defined terms were revised to better align with industry expectations and NAESB business practices.

Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

This defined term was revised to meet a FERC Order 693 Directive (paragraph 866) and is used in IRO-008-1 - Reliability Coordinator Operational Analyses and Real-time Assessments. Requirement R1 specifies that the Reliability Coordinator must perform an **Operational Planning Analysis**. By explicitly including "Interchange" in the definition of Operational Planning Analysis, the Reliability Coordinator must consider interchange when performing the study. Further, Requirement R2 specifies that the Reliability Coordinator must perform a Real-time Assessment. By explicitly including "Interchange" in the definition of Real-time Assessment, the Reliability Coordinator must consider interchange when performing the study. When the results of either of these studies indicate the need for action, the Reliability Coordinator is required to share the results per Requirement R3.

Proposed new definitions:

Reliability Adjustment Arranged Interchange – A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

> The proposed term **Reliability Adjustment Arrange Interchange** was developed to accurately reflect the types of Interchange that are adjusted for reliability reasons. This defined term aligns with industry expectations and NAESB business practices.

Composite Confirmed Interchange – The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.

> The defined term **Composite Confirmed Interchange** was developed to define what is to be included in INT-009-2, Requirement R1 to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities. This defined term aligns with industry expectations and NAESB business practices.

Attaining Balancing Authority: A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.

Native Balancing Authority: A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

> The defined terms **Attaining Balancing Authority and Native Balancing Authority** are necessary to define the various Balancing Authorities involved in the implementation of Dynamic Transfers and their relationships with regards to Dynamic Transfers. These defined terms were developed to align with industry expectations and NAESB business practices.

Exhibit I

Standard Drafting Team Roster for Project 2008-12

Project 2008-12 Coordinate Interchange Standards

Standard Drafting Team

Name and Title	Company and Address	Contact Info	Bio
Cheryl Mendrala Chair	ISO New England 1 Sullivan Rd Holyoke, MA 01040	413-535-4184 cmendrala@iso-ne.com	Cheryl Mendrala is a Principal Engineer at ISO New England where she has been involved with external transactions since the design phase of the Standard Market Design in 2001. She has been directly involved with the continued evolution of the various ISO New England markets as they relate to external transactions. Cheryl has also been actively involved in the NAESB and NERC committees that deal with interchange schedules for over 10 years. Cheryl has a Bachelor of Science degree in Mechanical Engineering from the University of Massachusetts and a Master of Science degree in Mechanical Engineering from Rensselaer Polytechnic Institute.
Robert Harshbarger Vice-chair	Puget Sound Energy 355 110th Avenue NE EST-06E Bellevue, WA 98004	206-604-3251 robert.harshbarger@pse.com	Bob is currently the OASIS Trading Manager overseeing Puget Sound Energy's OASIS implementation and related activities (17 years). At Puget, Bob has also worked in transmission planning (2 years), in Engineering Applications and Analysis (1 year), and in distribution automation projects (2 years). Prior to Puget, Bob was a college instructor at New Mexico State University (1 year), senior engineer at Pacific Gas and Electric's advanced EMS applications project (6 years), and a distribution engineer at Tucson Electric Power (2 years). Bob is and has been involved with various WECC, NERC, and NAESB committees and initiatives for the past 15 years. Bob has a Bachelor of Science in Electrical Engineering from University of Illinois and a Master of Science in Electrical Engineering from New Mexico State University. He is a registered professional engineer in the State of California and currently lives in Redmond, WA.
Kelly Bertholet Manager, Market Operations	Manitoba Hydro P.O. Box 815 STN MAIN Winnipeg, MB R3C-2P4	204-360-3084 kwbertholet@hydro.mb.ca	Kelly Bertholet is the Manager of Market Operations for Manitoba Hydro. In his 25 year career, Kelly has held numerous positions in Power Trading, Transmission Operations and Plant Operations.

David McRee	Duke Energy 526 S. Church St Charlotte, NC 28202	704-382-9841 david.mcree@duke-energy.com	David McRee is currently the Manager of the System Operating Center at Duke Energy in Charlotte, NC. He has worked for Duke Energy for 24 years after receiving his Electrical Engineering degree from North Carolina State University in 1990. David began his career at Catawba Nuclear Station as a testing engineer. After spending three years at the plant, he transferred into the Operations area supporting the System Operations Center (SOC). David has been in this area for 21 years and has worked as a System Coordinator, Reliability Coordinator, and SOC engineer. During this time, he was responsible for the deployment and training of the OASIS and the electronic tagging systems for the Duke Balancing Authority. In late 2012, he was moved from his technical function to become the SOC Manager. For the past 10 years, David has been the Subject Matter Expert for Duke on the NERC INT and EOP standards and coordinates the Emergency Capacity and Restoration Plans for the Duke Balancing Authority. David has worked with many industry teams over the past 20 years and is currently chairing the EOP Standard Drafting Team for NERC.
Mary Willey	Bonneville Power Administration PO BOX 491 Vancouver WA 98666	360-418-2234 mgwilley@bpa.gov	Mary is a Public Utilities Specialist (Technical Specialist) in the Commercial Systems Management Compliance group within the Transmission Scheduling Organization for the Bonneville Power Administration. Mary is a key partner in the preparation, review and submittal of documentation submitted for NERC/WECC audit and annual Interchange Standard compliance reporting. While performing these duties for the past seven years, Mary additionally is a member of the 2008-12, Coordinate Interchange Standards Draft Team and is an active participant in WECC business practice drafting efforts.
Stephen Crutchfield Standards Developer	North American Electric Reliability Corporation 3353 Peachtree Road, NE, Suite 600 - North Tower Atlanta, GA 30326	609-651-9455 Stephen.crutchfield@nerc.net	Stephen Crutchfield is the lead NERC Staff Coordinator for Project 2008-12, Coordinate Interchange Standards. Stephen began his career with NERC in May 2007. Prior to joining NERC, Stephen was a Project Manager with Shaw Energy Delivery Services, managing engineering and construction projects in the substation and transmission line fields. Stephen's background also includes experience with PJM as Manager of RTO Integration, working on the operations and markets integration of new members (AEP, ComEd, Dayton,

			Dominion and Duquesne) into PJM and southern seams operations issues with Progress Energy, Duke and TVA. Stephen also helped lead the team that was developing GridSouth in the dual roles of Organization Architect and Manager of Customer Support. Prior to GridSouth, Stephen was the Manager of Power System Operations Training at Progress Energy where he spent over 10 years training System Operators and Engineers. Overall, Stephen was with Progress Energy for 16 years. Stephen received his Bachelor of Arts in Physics from the University of Virginia and Masters of Science in Electrical Engineering from North Carolina State University. Stephen holds a Master of Science in Management degree, also from North Carolina State University.
Mallory Huggins Standards Developer	North American Electric Reliability Corporation 1325 G Street NW, Suite 600 Washington, DC 20005	202-644-8062 mallory.huggins@nerc.net	Mallory Huggins serves as a Standards Developer for NERC. She currently serves as the lead Standards Developer for Project 2010-02 – Connecting Facilities to the Grid and a supporting Standards Developer for Project 2008-12 and Project 2010-14.2 – Phase 2 of Balancing Authority Reliability-based Controls. Previously, she served as the lead Standards Developer on Project 2010-07 – Generator Requirements at the Transmission Interface, the Adequate Level of Reliability Task Force, and the VRF/VSL revision project. She also coordinates industry outreach and communication for NERC's standards department. Huggins has an M.A. in conflict resolution from Georgetown University and worked for FERC's Dispute Resolution Service during her two years of graduate school. She has training in facilitation, mediation, and negotiation and earned a B.A. in rhetoric and communication studies from the University of Richmond, with a focus on interpersonal communication and conflict.
Sean Cavote Standards Developer	North American Electric Reliability Corporation 3353 Peachtree Road, NE, Suite 600 - North Tower Atlanta, GA 30326	404-446-9697 sean.cavote@nerc.net	Sean Cavote is a NERC Standards Developer supporting Project 2008-12, Coordinate Interchange Standards. Sean began his career at NERC in January 2013. Prior to joining NERC Sean was an energy attorney at NiSource in Indianapolis and Van Ness Feldman in Washington, DC. Sean also has deep experience in power generation consulting. Sean received his Bachelor of Arts in Political Science from the University of Louisville and his

			Juris Doctor from the George Washington University Law School.