## 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.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

## 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.

**Comment [A1]:** Need to update when Cheryl sends the revisions.

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 | | | | | | | | | |
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| | | | | 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 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
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| 17. | Michael Gildea | Dominion | SERC | 1 |

| | | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
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| 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 |
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| 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 | | | | | | | | | |
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|---|---|---|---|---|
| 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 |
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| 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 |
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| 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 |

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| 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 |
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| 7. | Group | Denise Koehn | Bonneville Power Administration | X | | X | | X | X | | | | |

| | | Commenter | Organization | Industry Segment | | | | | | | | | |
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| | 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 |
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| 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 |
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| 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 |
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| 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 |
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| 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 | | | | | | | | | |
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| 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 |

| | | Commenter | Organization | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
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| 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 | | | | | | | | | |
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| 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.<br>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.<br>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.<br>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.<br>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.**<br>**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.**<br>**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** | | |

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td colspan="3">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.<br><br>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.<br><br>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).</td></tr>
<tr><td>Functional Model Working Group</td><td>Disagree</td><td>The Functional Model Working Group (FMWG) does not agree with removing the IA from the NERC standards.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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</td></tr>
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<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.<br><br>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.<br><br>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.<br><br>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.<br><br>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).<br><br>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.<br><br>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. –<br><br>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.<br><br>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.<br><br>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.<br><br>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.**<br>**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).**<br>**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.**<br>**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.<br>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.<br><br>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.**<br><br>**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.<br>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.**<br>**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:<br>R1.1 - “Load Balancing Authority” should be replaced with the defined term “Sink Balancing Authority” as defined in the NERC Glossary.<br>**The SDT has replaced the language as suggested.**<br>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.<br>**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.<br>**The information described is addressed in INT-006.**<br><br>R2.5 - Should indicate which entities are distributed the RFI.<br>**The information described is addressed in INT-006.**<br><br>R2.6 - Should indicate which entities are distributed the RFI.<br>**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**<br><br>**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.<br><br>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.**<br>**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.**<br>**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.<br><br>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.**<br><br>**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.<br>**The SDT has modified the requirements to include PSEs.**<br>**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.<br>**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.**<br>**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.<br>**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?<br>**The SDT has simplified R1 to address this concern.**<br>**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.**<br>**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.<br>**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.**<br>**R6: Sub-requirements 6.1 through 6.3 include a logical "and". Should this be a logical "or"?<br>**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."**<br>**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.<br>**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.<br>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)?<br>**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.**<br>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.<br>**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.<br>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.**<br>**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.**<br><br>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?<br><br>**The SDT has clarified the language by reordering the entities.**<br><br>R7.The concern described for R1 also applies to the one minute notification timing requirement included within R7.<br><br>**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.<br>**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.**<br>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.<br>**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.**<br>**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.<br>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<br>Item 1): Should “remaining for the TSR” be “remaining on the TSR”?<br>**The SDT has modified the langue to address this concern.**<br>**R3.1<br>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.<br>**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.<br>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.<br>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.<br>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.**<br>**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.**<br>**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”?<br>**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."**<br><br>**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.<br>**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<br>**The SDT will consider this when developing the measures for related requirements.**<br>(2) R8 is redundant with TOP-005-2 R2; and<br>(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).<br>**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.<br>**The SDT will consider this when developing the measures for related requirements.**<br>(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."<br>(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."<br>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.<br>**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.<br>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.<br>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:<br>(1) “Potentially required” is not measurable<br>**The SDT will consider this when developing the measures for related requirements.**<br>(2) R8 is redundant with TOP-005-2 R2; and<br>(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).<br>(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.<br>**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.<br>**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<br>**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.<br>**The SDT believes this is addressed in R4.4 by allowing for "potential" exceedances.**<br>(2) This requirement is redundant with IRO-009-1 R4<br>**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.**<br>(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?<br>**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.<br>**The SDT believes this is addressed in R4.4 by allowing for "potential" exceedances.**<br>(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?<br>**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.<br>**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.<br>**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.**<br>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.<br>**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?<br>**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.**<br>The default when there is a disagreement is that the BAs must check each Interchange Schedule and not just Net Interchange.<br>**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?<br>**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.**<br>The default when there is a disagreement is that the BAs must check each Interchange Schedule and not just Net Interchange.<br>**The SDT agrees that many entities will check each interchange schedule. However, the SDT is not requiring such procedures to be undertaken.**<br>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?<br>**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?<br>**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.**<br>The default when there is a disagreement is that the BAs must check each Interchange Schedule and not just Net Interchange.<br>**The SDT agrees that many entities will check each interchange schedule. However, the SDT is not requiring such procedures to be undertaken.**<br>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?<br>**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.<br>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.).<br>**The concepts in INT-011 were moved into the Guidelines and Technical Basis section of INT-006.**<br>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.<br>**This will be incorporated into the Implementation plan for the standards.**<br>INT-004-3 Dynamic Schedules<br>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.<br>**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.<br><br>**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.**<br><br>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.<br><br>**The SDT has changed the requirement to indicate that LSEs much make changes only if the receive notification of the need for such changes.**<br><br>INT-006-4 Evaluation of Interchange<br><br>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?<br><br>**The SDT has simplified R1 to address this concern.**<br><br>R3.1 Item 1): Should "remaining for the TSR" be "remaining on the TSR"?<br><br>**The SDT has modified the langue to address this concern.**<br><br>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.**<br><br>R6: Sub-requirements 6.1 through 6.3 include a logical "and". Should this be a logical "or"?<br><br>**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."**<br><br>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.<br><br>**INT-006 R6.5 requires that PSEs be included on the transition of any Arranged Interchange..**<br><br>INT-009-2 Implementation of Interchange<br><br>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.<br><br>**The SDT has removed the word "plus" and addressed the requirement by requiring the inclusion of the two values.**<br><br>INT-010-2 Initiating and modifying Interchange for Reliability<br><br>This standard needs to apply to Reliability Coordinators if the PPL-proposed R5 (below) is included.<br><br>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).<br><br>**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).<br>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.<br><br>**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.**<br><br>**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:**<br><br>**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.).**<br><br>**Real-time Assessment: An examination of existing and expected system conditions, including Interchange, conducted by collecting and** | | |

| Organization | Yes or No | Question 16 Comment |
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| **reviewing immediately available data.**<br><br>**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.**<br><br>**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:**<br><br>**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.).**<br><br>**Real-time Assessment: An examination of existing and expected system conditions, including Interchange, conducted by collecting and reviewing immediately available data.**<br><br>**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 |
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| **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.**<br><br>**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:**<br><br>**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.).**<br><br>**Real-time Assessment: An examination of existing and expected system conditions, including Interchange, conducted by collecting and reviewing immediately available data.**<br><br>**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 |

| Organization | Yes or No | Question 16 Comment |
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| | | between the proposed standards and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement. |
| **Response: Thank you for your comment.** | | |
| California ISO | Agree | SDT draft change run counter to present IA contracts in the West, negotiated and entered into in good faith. |
| **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.** | | |
| Independent Electricity System Operator | Disagree | We are not aware of any conflicts. |
| American Electric Power (AEP) | Agree | Yes, different Market models and structure, such as SPP. |
| **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.** | | |

**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 |
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| 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.<br>**INT-004 now addresses pseudo-ties.**<br>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 |
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| | | **This word is defined currently in the NERC Glossary, under "Request for Interchange."**<br><br>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.<br><br>**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.<br><br>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.**<br><br>**The definition of Confirmed Interchange has been updated, as have several other definitions related to Interchange.** | | |
| FirstEnergy | | FE has the following additional comments:<br><br>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.<br><br>**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** |

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| | | **alleviated the need for the language provided previously in the footnotes. .**<br>2. INT-004-3 –<br>(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.<br>**The SDT has eliminated the extraneous entities from the applicability.**<br>(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...".<br>**The SDT has modified the requirement similarly to the suggestion provided.**<br>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.<br>**The SDT has modified this to be the "first day of the second calendar quarter…"**<br>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?<br>**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?<br>**The SDT has replaced "Load" BA with "Sink" BA**<br>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. |

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| | | **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.**<br>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.<br>**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.**<br>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.<br>**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.**<br>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.<br>**INT-010 specifies responsibilities and actions that are different from those described in INT-006 and INT-009.**<br>INT-011: The Reliability Coordinator is in the Applicability section but is not mentioned in the requirements<br>**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?<br>**The SDT has replaced "Load" BA with "Sink" BA.**<br>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.<br>**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.**<br>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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| | | when the language in the requirements is only applicable to on-time AI.<br>**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.**<br>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.<br>**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.**<br>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.<br>**INT-010 specifies responsibilities and actions that are different from those described in INT-006 and INT-009.**<br>INT-011: The Reliability Coordinator is in the Applicability section but is not mentioned in the requirements<br>**The SDT has modified the applicability to eliminate this inconsistency.** |
| **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.<br>**The SDT has replaced this language with words that more accurately reflect the intent of the requirement.**<br>There are several places where the Load Balancing Authority is used. Why is this term used instead of Sink Balancing Authority?<br>**The SDT has replaced "Load" BA with "Sink" BA.**<br>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.<br>**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 |
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| | | **forecast. If they do have a forecast, it must be used.**<br>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.<br>**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.**<br>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.<br>**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.**<br>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.<br>**INT-010 specifies responsibilities and actions that are different from those described in INT-006 and INT-009.**<br>INT-011: The Reliability Coordinator is in the Applicability section but is not mentioned in the requirements<br>**The SDT has modified the applicability to eliminate this inconsistency.** |
| **Response:** | | |
| California ISO | | INT-004-3 Comments:<br>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."<br>**The SDT is not sure of the intent of this comment.**<br>R1.1 - The term "Load Serving, Purchasing-Selling Authority" should be changed to "Load-Serving Entity" as defined in the NERC Glossary.<br>**The SDT has replaced this language with words that more accurately reflect the intent of the requirement.**<br>There is a question pertaining to "Reloading Transactions" in Question #7 of the accompanying questionnaire.<br>**Please see Question 7 for response.** |

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| | | INT-006-4 Comments:<br>R1 - Appears to be missing the RFI distribution to the PSE.<br>**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.**<br>R2.1 - Missing valid energy product code is a valid reason for denial.<br>**The SDT does not believe missing such a code is an invalid reason for denial, but believes it is not mandatory for denial.**<br>R4 - Direct-current Tie Operator or Direct-Current Tie Operating Balancing Authority should be defined and added to the NERC Glossary.<br>**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”.**<br>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.<br>**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.**<br>INT-009-2 Comments:<br>Requirement numbering (R numbering and R sub-numbering) needs to be consistent between this and other INT Standards.<br>**The numbering has been fixed.**<br>R2 - The NERC definition defines the Net Interchange Schedule, it does not define Net Scheduled Interchange, although many use the terms interchangeably.<br>**Both terms are currently in the NERC Glossary.**<br>What is meant by the use of the word “term”?<br>**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.”**<br>INT-010-2 Comments:<br>There is a need to identify the default entity that creates the tag in requirements R1-R3 as the Load Serving |

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| | | Entity.<br>**The SDT believes that from a reliability perspective, there is no need to define who creates a tag.**<br>INT-011 Comments:<br>R1.1 - “Load Balancing Authority” should be replaced with the defined term “Sink Balancing Authority” as defined in the NERC Glossary.<br>**The SDT has made this changes as suggested.**<br>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.<br>**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.**<br>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.<br>**This is addressed in INT-006.**<br>R2.5 - Should indicate which entities are distributed the RFI.<br>**This is addressed in INT-006.**<br>R2.6 - Should indicate which entities are distributed the RFI.<br>**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 |

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| | | 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.<br>**The latest version of the standards posted for comment now address pseudo-ties.**<br>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.<br>**These concerns are addressed in INT-006.**<br>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.<br>**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.**<br>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.<br>**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.**<br>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.<br>**The latest version of the standards posted for comment now  address pseudo-ties .**<br>Since the maximum actual energy cannot exceed the transmission reservation that has already been reliably |

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| | | 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.<br>**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.**<br>INT-006-4 Rewrite Comments:<br>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.<br>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.<br>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.<br>**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:**<br>- **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** |

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| | | **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.**<br>- **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).**<br>- **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).**<br>**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.**<br>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.<br>**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** |

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| | | **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.**<br>Applicability: Agree with adding the 4.3 Reliability Coordinator and 4.4 Transmission Operator entities.<br>**Thank you for your supportive comment.**<br>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.<br>**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.**<br>Retirement of Standards<br>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.<br>**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.**<br>**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 |

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| | | the BA's ACE, though this may be unecessary as ACE is defined in other standards.<br>**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.**<br>INT-011-1 R1.1 refers to a Load Balancing Authority. Should this be Sink Balancing Authority?<br>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.<br>**The concepts of INT-011 have been moved into the Guidelines and Technical Basis section of INT-006.**<br>In general:<br>- the standards are wordy and written in a manner that is difficult to understand.<br>**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.**<br>- 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?<br>**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.<br>**Thank you for your supportive comments.**<br>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 |

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| | | "Load Balancing Authority." NERC suggests the CISDT either define these terms or consider alternate wording in the standard.<br><br>**On-time is defined in the timing tables. The SDT has added a footnote to make this clear.**<br>**The SDT has replaced the generic term "reliability adjustment" with the defined term "Reliability Adjustment Arranged Interchange."**<br>**The standard no longer used the abbreviation "SOL."**<br>**Transmission and Facilities are separately defined terms in the NERC glossary.**<br>**The SDT has removed the reference to the "Entity Registry" and replaced it with implementation-neutral language.**<br>**The SDT has replaced "Load Balancing Authority" with "Sink Balancing Authority."**<br><br>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.<br>**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<br>**The SDT is uncertain as to what new responsibilities are being referenced. Please provide further detail to the CISDT directly.**<br>- INT-009-2 Requirement R1 - for this requirement, you should not have to re-confirm schedules that have |

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| | | not changed from previous hours.<br>**The SDT has modified the requirement to not require verification every hour.** |
| **Response:** | | |
| PJM | | PJM would suggest the SDT directly address the issues that they the SDT propose to remedy:<br>1. Define the data that must be coordinated for reliability<br>- Magnitude<br>- Start and end times<br>- Rate of change<br>- Source/sink<br>2. Distinguish between coordination tools and reliability entities. For example:<br>- Require that BAs only implement CONFIRMED INTERCHANGE; then as sub-requirements list the acceptable means of doing that:<br>- 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<br>- By BA-to-adjacent BA checkout where using the same inter-area net values as confirmation that they met the coordination requirement<br>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.] |
| **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.** | | |
| Functional Model Working Group | | PLEASE NOTE THAT THE FMWG IS SUBMITTING COMMENTS ONLY TO QUESTION 2<br>The survey form does not provide the option to deselect the agree/disagree entry once it is checked.<br>All other responses should really be NO RESPONSE. |

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| **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<br><br>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.<br><br>WECC thanks the CISDT for the opportunity to provide comments. |
| **Response: Thank you for your supportive comments,** | | |