NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

Interchange Standard and Business Practices Meeting

Wednesday, April 21, 2004 — 8 a.m. to 5 p.m.

Thursday, April 22, 2004 — 8 a.m. to 5 p.m. (Interchange Subcommittee)
Friday, April 23, 2004 — 8 a.m. to noon (Interchange Subcommittee)

Hyatt Regency Islandia
1441 Quivira Road
San Diego, California
Phone: 619-224-1234 ■ Fax: 619-224-0348

Agenda

1. Administrative — **10 minutes**
- a. Welcome and Introductions – Chairman
- b. NERC and NAESB Antitrust Guidelines – Chairman
- c. Arrangements – Secretary
- d. Approval of Agenda – Chairman

2. Purpose of Meeting – Monroe Landrum — **20 minutes**
- a. Coordination of reliability standards and business standards

3. Accelerated Standards Transition – Gerry Cauley — **1 hour**
- a. Standards – Version 0
- b. Details of transition plan

4. Reliability and Business Groups Coordination – Joel Dison — **30 minutes**
- a. Tools – TSIN, Registry, E-Tagging, OASIS 1A and II

5. Interchange Issues and Concerns – Subcommittee Chairman — **3 hours**
- a. Committee actions related to Interchange
  - i) Karl Tammar
    - (1) ISO RTO Council seams issues
  - ii) Roman Carter – Chairman of NAESB CIBPTF
    - (1) Posting of interchange business practices
    - (2) Comments and issues identified from posting
  - iii) Mike Oatts – Chairman of NERC CISTDDT
    - (1) Posting of CI Standard
    - (2) Anticipated revisions for second posting
  - iv) Doug Hils – Chairman of NERC IS

(1) Policy 3 Reliability Standards and Compliance Templates
(2) Policy 3 as Version 0

6. Other Issues – Various Presenters **Remainder of Day**

a. The IA Function – John Simonelli
b. NERC Reliability Functional Model – Version 2 – TBD
c. Discuss "Interchange State" definitions and the Functional Model – Roman Carter
d. Discuss "Operating Authority Users Manual" for reliability and business standards – Al Boesch

Item 1. Administrative

a. Welcome and Introductions – Chairman

Monroe Landrum of Southern Company will chair the meeting. Mr. Landrum is the current chairman of the NAESB Information Technology Subcommittee and the NERC Transaction Information System Working Group, and past chairman of the OASIS Standards Collaborative.

The chairman will request introductions from the group.

b. Antitrust Guidelines – Chairman

The NERC and NAESB Antitrust Compliance Guidelines are attached for reference. The secretary will answer questions regarding these guidelines.

c. Arrangements – Secretary

Gordon Scott will act as secretary for the meeting. The secretary will review the meeting arrangements. The meeting begins on Wednesday, April 21 at 8 a.m. and adjourns at 5 p.m.

d. Approval of Agenda – Chairman

The chairman will ask for additional items or revisions to the agenda.

Action

The chairman will ask for approval of the agenda.

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NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or which might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. PROHIBITED ACTIVITIES

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

Approved by NERC Board of Trustees
June 14, 2002

III. ACTIVITIES THAT ARE PERMITTED

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation and Bylaws are followed in conducting NERC business. Other NERC procedures that may be applicable to a particular NERC activity include the following:

- Organization Standards Process Manual
- Transitional Process for Revising Existing NERC Operating Policies and Planning Standards
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.

- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.

- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

Item 2. Purpose of Meeting – Monroe Landrum

Background

The Interchange Subcommittee, Coordinate Interchange Business Practices Task Force, and Coordinate Interchange Standard Drafting Team met on October 27–28, 2003 in Cincinnati, Ohio. At that meeting, the groups began the process of ensuring that the development of business and reliability standards are coordinated and harmonized, and that practicable efforts would be made to eliminate overlap and duplication of efforts in the drafting of interchange standards.

The groups decided at the Cincinnati meeting that the chairmen of the groups would call other Interchange Standard and Business Practice meetings when necessary.

The industry continues to move forward with Standards development.

- The CIBPTF has posted business practices related to interchange for public comment.
- Other NAESB committees have been formed and are active in standard development.
- The Coordinate Interchange Standard has received comments from its first posting.
- The NERC board approved version 2 of the NERC Reliability Functional Model.
- NERC has proposed developing Version 0 of the standards. These standards will be coordinated with NAESB and the IRC.

Action and Deliverables

The groups should discuss the following:

- How the proposed Version 0 of the standards will affect the work of the groups.

- How to continue the coordination of reliability standards and business standards.

The groups should provide input into:

- The NAESB Coordinate Interchange Business Practice Standards — Request for Interchange (RFI).

- The NERC Coordinate Interchange Standard.

- ISO RTO Council seams issues.

- Policy 3 as Version 0

Item 3. Accelerated Standards Transition – Gerry Cauley

Background

Gerry Cauley, NERC Director of Standards, will lead the discussion on the proposed accelerated standards transition; including, the process and timetable for developing Version 0, and how the NAESB business practices will be managed in the process.

Version 0 of the standards would accelerate the transition from existing NERC operating policies, planning standards, and compliance templates, to a single set of NERC standards by the end of 2004. This project would include the following objectives:

- Translate all existing operating policies, planning standards, and compliance templates into a single baseline "Version 0" set of new reliability standards. The content of these standards would not change from today's reliability rules with two exceptions:

    1. The Functional Model designations would be used (e.g. balancing authority, reliability authority, etc.).
    2. Business practices in the current NERC policies and standards would be allocated to NAESB to adopt as business practices.

Action

The groups should be prepared to discuss with Gerry how Version 0 would affect the work of the interchange groups.

Attachments

3a NERC Standard Development Bulletin – April 2004

3b Letter to the BOT, Accelerating the NERC Standards Transition – April 14, 2004

From: Gerry W. Cauley [Gerry.Cauley@nerc.net]
Sent: Friday, April 02, 2004 3:20 PM
Subject: NERC Standards Development Bulletin - April 2004
This email was sent to the standards List Serve

NERC Home

Reliability Standards Home

Standards Authorization Committee (SAC)

Joint Interface Committee (JIC)

Registered Ballot Body

Contact Us

NERC Standards Development Bulletin

April 2004

August 14, 2003, Blackout Drives an Accelerated Standards Transition

The August 14, 2003, blackout points to an urgent need for clear and measurable reliability standards – now. On an interim basis, NERC and regional compliance programs will conduct audits using compliance templates that are based on existing NERC operating policies and planning standards. In our current state of transition to new reliability standards, the industry is working with operating policies, planning standards, compliance templates, and the emerging reliability standards. This creates a multiplicity of standards forums and processes that is stretching industry resources. And that is just for reliability – many also choose to participate in business practice standards development through the North American Energy Standards Board (NAESB).

The NERC Standards Transition Management Team (STMT) consists of the vice chairmen of all NERC committees, including the Standards Authorization Committee (SAC). The STMT is proposing a plan to accelerate the transition from existing NERC operating policies, planning standards, and compliance templates, to a single set of NERC standards under a single process by the end of 2004. This project would include the following objectives:

- Translate all existing operating policies, planning standards, and compliance templates into a single baseline "Version 0" set of new reliability standards. The content of these standards would not change from today's reliability rules with two exceptions:

  1. The Functional Model designations would be used (e.g. balancing authority, reliability authority, etc.).
  2. Business practices in the current NERC policies

and standards would be allocated to NAESB to adopt as business practices.

- Complete an initial registration (not certification) of all functions to which the initial set of standards would apply.
- In November 2004 have the NERC technical committees approve the Version 0 standards as a true copy of existing reliability rules and in December have the Registered Ballot Body vote to approve the standards. At this point, beginning January 1, 2005, there would only be one set of NERC standards going forward and one process for revising the standards or adding new standards.
- Preserve the momentum of existing SAR and standards drafting teams to allow the emerging new standards to become replacements or revisions to the Version 0 standards.

This is a very challenging set of goals, but the urgency to achieve these goals is great. A detailed transition plan will be available on April 15.

Cyber Security Standard

The Cyber Security SAR drafting team has completed its work on the SAR for a permanent Cyber Security Standard (1300) and is requesting the SAC to authorize proceeding to draft the standard. Recognizing that the development of this standard will not be complete prior to the August 13, 2004, expiration of the existing Interim Cyber Security Standard (1200), the drafting team is also requesting the SAC to consider balloting the interim standard for a one-year extension to August 2005.

Standards and SARs Available for Comment

The Operate Within Interconnection Reliability Operating Limits (IROL) draft standard is posted for comments through April 14. This is expected to be the final posting before a second ballot on this draft standard. The drafting team has focused on addressing comments received in the first ballot of the standard.

The Certification of the Balancing Authority Function draft standard is being posted on April 2 for a 45-day comment period.

The status of other SARs and proposed standards are summarized below.

Gerry Cauley, Director – Standards

Reliability Standards Under Development

100	**Coordinate Operations** **Purpose:** To ensure that the operations of each reliability authority (RA) function are coordinated such that they will not have an adverse impact on the reliability of other RAs and to preserve the reliability benefits of interconnected operations. **Status:** Drafting Team is considering comments from the first posting of the proposed standard. A second posting of the draft standard is expected on May 1.
200	**Operate Within Interconnection Reliability Operating Limits** **Purpose:** The purpose of this standard is to prevent instability, uncontrolled separation or cascading outages that adversely impact the reliability of the bulk transmission system. **Status:** A revised draft standard is posted for comment through April 14. A second ballot of the standard is anticipated following consideration of comments.
300	**Balance Resources and Demand** **Purpose:** To maintain Interconnection scheduled frequency within a predefined frequency profile under all conditions (i.e., normal and abnormal), to prevent unwarranted load shedding and to prevent frequency related cascading collapse of the interconnected grid. **Status:** Comments from first posting of the draft standard are under consideration. The drafting team plans to post the next version of the draft standard by May 15.
400	**Coordinate Interchange** **Purpose:** To ensure that the implementation of transactions between sink and source balancing authorities are coordinated by the interchange authority such that the following reliability objectives are met: ▪ Each interchange schedule is checked for reliability before it is implemented.

	▪ The balancing authorities implement the Interchange Schedule exactly as agreed upon in the interchange confirmation process. ▪ Interchange schedule information is available for reliability assessments. **Status:** Comments from posting of first draft of standard are under review.
500	**Assess Transmission Future Needs and Develop Transmission Plans** **Purpose:** To establish a standard for assessing and planning transmission systems in North America. The transmission system must be assessed and planned to ensure that it performs its intended functions in providing reliable delivery of power for the future needs of customers. **Status:** SAR drafting is underway.
600	**Determine Facility Ratings, Operating Limits, and Transfer Capabilities** **Purpose:** Determine facility ratings, system operating limits and transfer capabilities necessary to plan and operate the bulk electric system within predefined facility and operating limits such that cascading outages, uncontrolled system separation and voltage and transient instability are avoided. **Status:** Comments on draft standard are under review. Will post revised draft standard by May 1 for 30-day pre-ballot period and anticipate going to ballot afterwards.
700	**Define (Physical) Connection Requirements** **Purpose:** To establish a standard for the proper physical connection of generation substations, transmission facilities, and load substations to the transmission systems to maintain reliability. **Status:** SAR approved for development. Not started yet.
800	**Design, Install and Coordinate Control and Protection Systems** **Purpose:** To establish a standard for designing, coordinating and installing and maintaining

	automatic control and protection systems to provide for system performance within pre-defined limits. (For the purpose of this standard, automatic control devices include such facilities as Power System Stabilizers, Static Var Compensators, HVDC Modulation, Out of Step Relaying, etc.) **Status:** SAR approved for development. Not started yet.
900	**Monitor and Analyze Disturbances, Events and Conditions** **Purpose:** To establish a standard for evaluation and reporting of disturbances, events and conditions on the bulk electric system to determine how the power system responded to the events. The analysis is needed to make adjustments and/or modifications to the power system, procedures or standards to reduce the likelihood of an impact of future similar disturbances. **Status:** SAR approved for development. Not started yet.
1000	**Prepare for and Respond to Abnormal or Emergency Conditions** **Purpose:** To establish a consistent, uniformly applied standard for the development, coordination, implementation and maintenance of emergency plans. To require that an executable plan be in place to provide guidance for appropriate operation following conditions that have disrupted normal system operation. **Status:** SAR approved for development. Not started yet.
1100	**Prepare for and Respond to Blackout or Island Conditions** **Purpose:** To establish a consistent, uniformly applied standard for the development, coordination, implementation and maintenance of restoration plans. To require that an executable plan be in place to provide guidance for restoration of normal system operation following a blackout or island condition. **Status:** SAR approved for development. Not started yet.

1200	**Cyber Security (Urgent Action)** **Purpose:** To reduce risks to the reliability of the bulk electric systems from any compromise of critical cyber assets. **Status:** SAC considering a request to ballot a one-year extension of the interim standard.
1300	**Cyber Security (Permanent)** **Purpose:** To reduce risks to the reliability of the bulk electric systems from any compromise of critical cyber assets (computers, software and communication networks) that support those systems. Note: This standard is intended as a permanent replacement of the urgent action standard addressing the same issue. **Status:** SAR comment review completed and ready for standard drafting.
1400	**Certification of the Balancing Authority Function** **Purpose:** To ensure that each entity that wants to be recognized as a balancing authority has the capability of performing the responsibilities assigned to the balancing authority function. **Status:** Draft standard ready for posting. Expected to post on April 2 for 45 day comment period.
1500	**Certification of the Interchange Authority Function** **Purpose:** To ensure that each entity that wants to be recognized as an interchange authority has the capability of performing the responsibilities assigned to the interchange authority function. **Status:** Standard drafting underway.
1600	**Certification of the Reliability Authority Function** **Purpose:** To ensure that each entity that wants to be recognized as a reliability authority has the capability of performing the responsibilities assigned to the reliability authority function.

	Status: Standard drafting underway.
1700	**Certification of the Transmission Operator Function** **Purpose:** To ensure that each entity that wants to be recognized as a transmission operator has the capability of performing the responsibilities assigned to the transmission operator function. **Status:** Standard drafting underway.
☐	**Amend Standards Process Manual** **Purpose:** The purpose of this SAR is to amend the NERC Reliability Standards Process Manual to remove the requirement that all modifications to the process manual be accomplished through the standards process (i.e. initiate SAR, collect industry comment, ballot etc). The SAC believes that certain parts of the process manual, (those dealing with process or procedures) should be changed by SAC, with approval by the Board of Trustees, and other parts (those dealing with fundamental tenets of the process) should only be changed with stakeholder recommendation and approval by the Board of Trustees. This SAR will allow needed changes to be made with less burden on the industry and without confusing process manual changes with standards development. **Status:** SAR Drafting Team assigned and SAR in development. This effort is linked to the standards transition.
☐	**Reliability Standards Process Manual - Revision to Step 2** **Purpose:** To extend the public comment period for Step 2 (Solicit Public Comments on the SAR) of the Reliability Standards. The current 30 day response period does not provide adequate time for some Regional Councils and others to circulate the announced SARs; to draft Regional comments and positions; circulate those comments to appropriate committees and then meet with those committees to discuss, revise and approve a final position. To date, the comment periods have been extended to accommodate the lack of responses. Part of this may be educational, but a part of this lack of response is the lack of discussion time. Step 2 - Solicitation of Public Comments: the comment period must be increased to a minimum

of 60 days. Other comment periods (e.g., Balloting periods) of less than 60 days should also be considered for extensions to at least 60 days.

Status: Comments under review.

This bulletin is intended to provide recipients with the latest news concerning the development of NERC reliability standards. If you have any questions, comments, or suggestions on how we can improve our bulletin, please contact Gerry Cauley at Gerry.Cauley@nerc.net.

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NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

April 14, 2004

To: Board of Trustees

From: Standards Transition Management Team
Standards Authorization Committee
Operating Committee
Planning Committee
Market Committee
Compliance & Certification Committee
Critical Infrastructure Protection Committee
Regional Managers

Accelerating the NERC Standards Transition

The undersigned NERC committees request that the Board of Trustees endorse the goals stated below for an accelerated transition to NERC reliability standards.

The August 14, 2003 blackout underscores the urgent need for reliability standards that are clear, measurable, and enforceable – now. The Board's approval of compliance templates on April 2 was an immediate response to sharpen the measures used for compliance enforcement. Also, the standing committees are currently balloting proposed revisions that clarify and sharpen three operating policies to address specific lessons from August 14.

On a broader scale, however, NERC faces a potentially protracted transition to enforceable reliability standards developed through the ANSI-accredited process. In the current environment, a multi-year transition is unacceptable. The U.S./Canada Power System Outage Task Force says as much in Recommendation 25 of its April 5 final report on the blackout:

> *NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards.*

The Standards Transition Management Team, with groundswell of support among NERC committees, the regions, and the industry, proposes an accelerated transition project to convert the existing operating policies, planning standards and compliance templates into a baseline Version 0 set of NERC reliability standards for adoption by the Board of Trustees at its February 2005 meeting.

The accelerated standards transition project will:

- Utilize the same reliability requirements documented in the current operating policies, planning standards, and compliance templates.
- Delegate through the Joint Interface Committee any business practices identified in the translation to the North American Energy Standards Board or ISO/RTO Council for adoption as a complementary business practice standard.
- Complete an initial registration of entities performing functions identified in the Functional Model and incorporate those functional designations into the NERC standards.
- Revise the ANSI-accredited standards process to be more streamlined and responsive to reliability issues.
- Upon adoption of the Version 0 standards, retire existing operating policies, planning standards, and compliance templates to work from there forward with a single set of NERC reliability standards.

The undersigned NERC committees:

1. Are moving expeditiously to achieve the goals stated above to allow the Board to adopt the Version 0 reliability standards at its February 2005 Board meeting;
2. Believe that the existing ANSI-accredited standards process can and should be used to adopt the Version 0 reliability standards; and
3. Commit to work with NAESB, the IRC, the Reliability Regions, and the industry to achieve the stated goals.

Linda Campbell
Chairman, Standards Authorization Committee

Mark Fydrich
Chairman, Operating Committee

Glenn Ross
Chairman, Planning Committee

Bob Harbour
Chairman, Compliance & Certification Committee

Stuart Brindley
Chairman, Critical Infrastructure Protection Committee

Mike Grim
Chairman, Market Committee

Ed Schwerdt
Chairman, Regional Managers

Standards Transition Management Team

cc: SAC, OC, PC, CCC, CIPC, MC, RM, STMT

Item 4. Reliability and Business Groups Coordination – Joel Dison

Background

The officers of the Operating Committee's subcommittees met in New Orleans on February 19−20 along with the members of the Coordinate Interchange Standard (Standard 400) Drafting Team, NAESB Executive Director Rae McQuade, and representatives of the NAESB Coordinate Interchange Business Practices Task Force. Joel Dison provided a presentation that described the next generation of tools that will be used by the industry for interchange and how those tools should be developed. Coordination between NERC, NAESB, IRC, and other groups is crucial for successful implementation of these tools.

Joel Dison will lead the discussion on the coordinated effort needed for OASIS II. OASIS II will probably (as a system) span across NAESB, NERC, and FERC functional areas. It will need to support physical market models as well as financial market models. A clear "upgrade path" for people who want to leverage their existing OASIS and E-Tag software is needed, including:

- A market-oriented solution that optimizes the market interchange scheduling function. "Market Scheduling" covers building transactions and getting initial approvals (and is handled by NAESB).

- A reliability-oriented solution that meets the needs of the functional model with regard to operational interchange scheduling "Operational Scheduling" covers the IA sanity check, IA to BA checkouts, and RA review (and is handled by NERC).

- A set of interfaces to allow for market activity within a ISO/RTO/TP. "Market Activities" including buying and selling energy, transmission, and ancillary services is developed by RTOS/TPs and NAESB.

- A "market/reliability interface" between the two, called the Interchange Authority that would tie markets and reliability together (*This would jointly be developed by NERC, NAESB, and the IRC*). The "IA" will serve as the bridge between "Market Scheduling" and "Operations Scheduling."

Item 5. Interchange Issues and Concerns – Subcommittee Chairman

Background

The leaders of the following groups will provide an update of the groups current work and discuss the current and future issues being addressed by their groups:

- Karl Tammar - ISO RTO Council
    - Seams issues
- Roman Carter – Chairman of NAESB CIBPTF
    - Posting and comments on interchange business practices
    - Comments and issues identified from posting
- Mike Oatts – Chairman of NERC CISTDDT
    - Posting of CI Standard
    - Anticipated revisions for second posting
- Doug Hils – Chairman of NERC IS
    - Policy 3 Reliability Standards and Compliance Templates
    - Policy 3 as Version 0

Attachments

5a ISO/RTO Council 2004 Annual Work Plan for Standards Development and Standardization Activities

5b Latest draft of the NAESB Coordinate Interchange Business Practice Standard (Request For Interchange, RFI). Note: the CIBP Standard Flow Diagram located on the last page of the document.

The CISTDDT's Coordinate Interchange Standard is located at: http://www.nerc.com/~filez/standards/Coordinate-Interchange.html. Please review the Standard Reference Document that is posted with Version 1 of the draft standard.

5c Policy 3 – Standards Reference Table

ISO/RTO Council 2004 Annual Work Plan for Standards Development and Standardization Activities

The ISO/RTO Council ("IRC") will participate in industry standards development efforts with NERC and NAESB. The primary mechanism for coordinating and presenting consensus positions to the industry will be through the IRC's Standards Review Committee ("SRC").

Reliability Standards Development

ISO/RTOs will participate in the development and prepare consensus comments and positions, as appropriate, for following Reliability standards that NERC plans to have developed during 2004:

1. Cyber Security
2. Assess Transmission Future Needs and Develop Transmission Plans
3. Balance Resources and Demand
4. Organizational Certification
5. Coordinate Interchange
6. Coordinate Operations
7. Interconnection Requirements
8. Design, Install and Coordinate Control and Protection Systems
9. Determine Facility Ratings, Operating Limits, and Transfer Capabilities
10. Monitor and Analyze Disturbances, Events and Conditions
11. Operate Within Transmission Limits
12. Prepare for and Respond to Abnormal or Emergency Conditions
13. Prepare for and Respond to Blackout or Island Conditions

The ISO/RTOs will participate in development efforts and provide consensus comments and positions, as appropriate, on the following reliability standards related activities with NERC:

Functional Model

The Model provides the foundation and framework upon which NERC will develop and maintain its Reliability Standards. While the Model is not a standard, and does not have compliance requirements, the Reliability Standards must respect the definitions and interrelationships contained in the Model. NERC is updated Version 1 of the Model and the standing committees approved Version 2 at their November 2003 meetings.

Existing Operating Policies and Planning Standards

Maintain and consider revisions, as appropriate, to existing Operating Policies and Planning Standards until replaced by NERC Reliability Standards, under NERC's "Transitional Process for Revising Existing NERC Operating Policies and Planning Standards."

NERC anticipates the following changes:

1. Policy 3, “Interchange,” and Appendix 3A4, “Required and Correctable Tag Data,” (removing Market Dispatch)
2. Appendix 1D, “Time Error Correction,” (revise time error initiation)
3. Appendix 9C1B, “Interchange Transaction Reallocation During TLR Levels 3a and 5a.”

Standards Transition

The ISO/RTOs will actively engage in committee (i.e. SAC) activities to assist in the transition from existing NERC operating policies and planning standards to reliability standards, with a goal of completing the transition by December 2006. This includes participation in determining what parts of existing operating policies and planning standards should become business practice standards and what business practice standards are needed to implement the emerging reliability standards.

Business Standards Development Activities With NAESB

The ISO/RTOs will assist NAESB in the development of business standards by providing the perspectives and expertise of subject matter experts, as appropriate. The IRC will work with the NAESB WEQ’s Subcommittees, Task Forces, and working groups as they assess issues for potential market impacts and needs for market standards. Through the SRC, the ISOs/RTOs will advise NAESB on issues identified, submit comments in the standards process, and provide joint responses to NAESB.

The IRC will work with NAESB on the following issues in 2004:

- Market Seams
- Complimentary business practices to NERC Reliability Standards
- OASIS Standards
- Electronic Scheduling Issues
- Other significant Wholesale Electric Market Operations and Standardization issues, as they may arise.

Coordination with NAESB and NERC

One of the goals of the MOU is to establish and implement a process to coordinate work efforts among NERC, the NAESB WEQ and the IRC in a manner that avoids overlap and duplication of effort. The IRC, through its JIC representatives and the SRC, will work jointly with NAESB and NERC to establish a mutually agreeable approach to coordinate standards development and related work efforts of each organization.

Inter-ISO/RTO Information Technology

The ISO/RTOs will look to identify appropriate technologies and opportunities for standardizing inter-ISO/RTO Information Technology (“IT”) processes. Through the IRC’s Information Technology Committee (“ITC”), the ISO/RTOs will seek to adopt standard technologies and standardize processes and data exchanges unique to ISO/RTOs.

The IRC IT Committee is actively engaged in three initiatives:

1. Data initiative – defines the content of messages exchanged between ISO/RTOs
2. Message Transmission – the mechanics of data exchange
3. Common User Portal – defines interface to create and retrieve messages

The Data initiative will be based on the Common Information Model ("CIM") standard from EPRI. This will be extended to include market data. The planning phase of this initiative is complete. The next steps are to solicit bids from various vendors and apply this technology to inter-ISO/RTO applications that this initiative would add value to.

The Message Transmission initiative will enable ISO/RTOs to access data across ISO/RTOs through a common portal. This will provide benefits in reliability coordination, outage management, and seams management. Once the scope and schedule are finalized, an implementation schedule will be developed

The Common User Portal will simplify information exchange processes with the ISO/RTOs. It will reduce development costs for each ISO/RTO and transaction costs for market participants. A development plan and requirements schedule is being prepared.

Technologies that may be identified as potential standards that may be applied on a North American basis will be proposed and coordinated through the IRC's Standards Review Committee.

NAESB Coordinate Interchange Business Practice Standard (Request For Interchange, RFI)

Background:

In light of the continuing restructuring of the Electric industry, and FERC's rulemaking to ensure open and non-discriminatory access to the nation's transmission systems, NERC is developing Reliability Standards to replace current Operating Policies and Procedures.

With regards to Policy 3, NERC currently is developing the Coordinate Interchange Standard to address the reliability issues associated with bilateral Interchange. The Standard is being developed using the Functional Model as a basis for defining the "Functions" necessary for Bulk Electric System reliability rather than the existing NERC Operating Policies for "Control Areas".

Introduction:

The NAESB Standards Review Subcommittee requested the development of a NAESB Business Practice Standard complementary to NERC's Coordinate Interchange Standard in June, 2003. This Standard development was approved by the Joint Interface Committee (JIC) representatives from NERC, NAESB, and RTO/ISO and assigned to NAESB for development.

This Standard identifies market-supported processes necessary to facilitate fair & "equitable" Interchange practices. It specifies the arrangements that need to be made and the data that needs to be communicated to the Interchange Authority (IA) and to all involved parties of the Request for Interchange (RFI) in order for Interchange to take place between Source and Sink Balancing Authorities (BA). It also implements the flow of data and approval mechanisms to facilitate Interchange.

Although this Standard specifies that NAESB is to determine the protocols needed to implement the Standard, it is not NAESB's intent to replace the existing ETAG specifications and protocols.

This Standard only covers the business arrangements and data requirements necessary to get the RFI to the IA and transition it into Arranged Interchange. The transition from Arranged Interchange to Confirmed Interchange and ultimately to Implemented Interchange will be accomplished in accordance with NERC Standards.

The Standard recognizes that FERC approved tariffs may supersede some provisions in this Standard.

The Standard applies Functional Model definitions to provide consistency with NERC's Reliability Standards. Terms used in this Standard which are defined by the Functional Model are not defined herein.

Until such time that the Entities defined by the NERC Functional Model are certified, the existing entities currently performing those functions will continue to do so.

Terms defined in the proposed NERC Coordinate Interchange Standard are included for reference only. Although these terms have not been approved as a Standard, the ESS believes these definitions will provide clarity to the various transition states of Interchange. For the purposes of this standard, only these terms are defined as follows:

> Arranged Interchange – The state where required information is provided to the Interchange Authority
>
> Confirmed Interchange - The state where the Interchange Authority has verified the Arranged Interchange and it is provided to the Balancing Authorities.
>
> Interchange – Energy transfers that cross Balancing Authority boundaries.
>
> Implemented Interchange- The state where the Balancing Authority enters the Confirmed Interchange into its area control error (ACE) equation's net scheduled Interchange component

Definitions

RFI Standard 1.0 For the purposes of this Standard, the following definitions shall be applied:

RFI Standard 1.1 Approval Entities – Those entities responsible for providing active approvals during the Market and/or Reliability Periods.

RFI Standard 1.2 Interchange Block Accounting – Energy accounting that assumes a beginning and ending ramp time of zero minutes. For accounting purposes, this moves the energy associated with the starting and ending ramps into the adjacent starting and ending clock time of the Interchange.

RFI Standard 1.3 Market Adjustment – A desired modification to the energy and/or transmission profile during the Confirmed Interchange period.

RFI Standard 1.4 Market Assembly – Function responsible for coordinating the submittal of the completed and balanced RFI from the Requesting PSE, or its designee, to the Interchange Authority.

RFI Standard 1.5 Market Period – The period of time when a Requesting PSE is making purchase, sale, and Transmission service arrangements needed to support a RFI.

RFI Standard 1.6 Reliability Period – The segment of time from when the IA has received the RFI from the requesting PSE, or its designee, to physical implementation (beginning of ramp time).

RFI Standard 1.7 Request For Interchange, RFI- A collection of data as defined in the NAESB RFI Datasheet to be submitted to the IA for the purpose of implementing bilateral Interchange.

RFI Standard 1.8 Requesting PSE – The PSE submitting the Request For Interchange (RFI). Under current policy this entity would be called the "Tag Author".

RFI Standard 1.9 Sink BA – The Balancing Authority responsible for monitoring and/or controlling the load identified as the sink of a bilateral Interchange.

. **RFI Standard 1.10** Source BA – The Balancing Authority responsible for monitoring and/or controlling the generation identified as the source of a bilateral Interchange.

. **RFI Standard 1.11** Interchange Correction – Modifications to non-reliability data of a Request For Interchange (RFI) while it is Arranged Interchange. This non-reliability data is located in the NAESB RFI Datasheet and is labeled as "correctable".

Business Practices

RFI Standard 2.0 All requests to implement bilateral Interchange shall be accomplished by the submission of a completed "Request For Interchange", RFI, to the Interchange Authority (IA).

RFI Standard 2.1 A completed RFI shall contain, at a minimum, the NERC required information specified in the most current version of the **NAESB RFI Datasheet** (attached).

RFI Standard 2.2 It shall be the responsibility of the load serving Purchasing-Selling-Entity (PSE), or their designee, to ensure the completed RFI has been submitted to IA.

RFI Standard 3.0 All energy purchase, energy sale, and Transmission service arrangements necessary to implement the bilateral Interchange shall be performed during the Market Period.

RFI Standard 4.0 The Requesting PSE shall verify all necessary business and transmission arrangements prior to the RFI being submitting to the IA and shall distribute a copy of the RFI to all involved parties. At its discretion, the Requesting PSE may defer this responsibility to the Market Assembly Function.

> **RFI Standard 4.1** In the current ETAG environment, the Market Assembly Function shall be accomplished by the Tagging Authority.

RFI Standard 5.0 The RFI shall be submitted to the IA (and to all other entities) in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetables** (attached).

> **RFI Standard 5.1** Upon receipt of the RFI by the IA, the RFI transitions into Arranged Interchange.

RFI Standard 6.0 The Arranged Interchange shall be assessed by all reliability Approval Entities and those assessments communicated back to the IA in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetables.**

> **RFI Standard 6.1** The results of that assessment shall be promptly communicated by the IA to all involved parties.
>
> **RFI Standard 6.2** All denials of a requested RFI by any reliability Approval Entity shall be communicated to all involved parties and shall be accompanied by the reason for such denial.

RFI Standard 7.0 Any changes to the status of the RFI shall be communicated by the IA to all involved parties of the RFI, including BAs, IAs, RAs, all PSEs , and the TSPs.

> **RFI Standard 7.1** In the current ETAG environment this shall be accomplished by the Tagging Authority.

RFI Standard 8.0 The primary method for submitting a RFI to the IA shall be by electronic means using protocols to be determined by NAESB.

RFI Standard 8.1 A backup or redundant electronic system shall be available for immediate use should the primary electronic means become disabled.

RFI Standard 8.2 Submitting a RFI to the IA via facsimile is acceptable only as a last resort when the electronic means and its required backup or redundant system are not available.

RFI Standard 8.3 Until such time as NERC and/or NAESB establish replacement protocols, the preferred method of submitting data to the IA shall be the most current version of the NERC E-Tag Specifications.

RFI Standard 9.0 Corrections to the Arranged Interchange shall be allowed until the Arranged Interchange has been approved by the reliability Approval Entities.

RFI Standard 9.1 Timing for corrections shall be in accordance with the **NAESB RFI Submission and Response Timetables**.

RFI Standard 10.0 Market adjustments made to the Confirmed Interchange by the PSE, or their designee, must be submitted to the IA and the reliability Approval Entities.

RFI Standard 10.1 Timing of the approval assessment on the Market Adjustment by the reliability Approval Entities shall be in accordance with the NAESB **RFI Submission and Response Timetables**. If the adjustment is denied by any Approval Entity, the original request remains valid for the original RFI duration period.

RFI Standard 11.0 All parties involved in the bilateral Interchange shall have, or arrange to have, personnel on site and immediately available 24 x 7 for notification of changes to the Request for Interchange.

RFI Standard 11.1 The personnel shall be available from the beginning of the Market Period through the implementation of the Confirmed Interchange.

RFI Standard 12.0 Unless provided for under a FERC approved market mechanism, energy accounting for all RFIs shall be accomplished via Interchange Block Accounting.

RFI Standard 13.0 Settlement of losses shall be either handled as financial or as payment in-kind.

RFI Standard 13.1 For losses handled as payment in-kind, the PSE, or its designee, shall communicate to the IA, via a RFI (either the original RFI or separate RFIs), the MW losses and the entity the losses are with for each TSP/BA along the Interchange path.

RFI Standard 14.0 Default ramp rates for the North American Interconnection shall be as follows:

RFI Standard 14.1 Default ramp rate for the Eastern Interconnection shall be 10 minutes equally across the start and end times of the RFI unless otherwise agreed to by all parties involved in the RFI .

RFI Standard 14.2 Default ramp rate for the Western Interconnection shall be 20 minutes equally across the start and end times of the RFI unless otherwise agreed to by all parties involved in the RFI.

NAESB RFI Datasheet

(Request For Interchange)

Required and Correctable Data

Version 1

A. New Requests For Interchange
B. Market Related Profile Modifications (Market Adjustment)

A. New Requests For Interchange

A **new RFI** is an RFI that has not yet been implemented or confirmed for implementation. Such RFI must be presented to those entities that are responsible for the implementation of the RFI in order that they may **evaluate** the Request and determine whether or not it can be implemented. The following information is to be used to describe such a RFI.

1. Market Information

1.1. Financial Path (Required) – the description of financially responsible parties for the Interchange in order. This will typically start with a GPE and finish with a LSE, with optionally Intermediate PSE'S between the two.

1.1.1. Energy Title Holder(s) (Required) – the identity of the entities financially responsible to take and/or deliver the energy as described in the physical path. This will typically start with a GPE and finish with a LSE, with optionally Intermediate PSE'S between the two.

1.1.1.1. Energy Product Type (Correctable) – the type of energy delivered by the Energy Title Holder.

1.1.1.2. Contract Number(s) (Correctable) – reference to a INTERCHANGE entered into by the Energy Title Holder with one or more other participants in the RFI.

1.1.1.3. Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.

2. Physical Information

2.1. Physical Path (Required) – the description of physically scheduling parties for the Interchange in order and related to the financially responsible parties described above. This will always contain a Generation segment, at least one Transmission segment, and a LOAD segment.

2.1.1. Generation (Required) – set of data describing the physical and contractual characteristics of the energy source.

2.1.1.1. Resource Service Point (Required) – the physical point at which the energy is being generated. This may vary in granularity, dependent on local business practices.

2.1.1.2. Contract Number(s) (Correctable) – reference to a schedule or agreement entered into by the Generation Providing Entity and the Generator Operator.

2.1.1.3. Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.

2.1.1.4. Energy Profile (Required) – energy to be produced by the generator for this RFI.

2.1.2. Transmission (Required) – set of data describing the physical and contractual characteristics of a wheel (import, export, or through).

2.1.2.1 Transmission Provider (Required) – the identity of the transmission provider that is wheeling the energy.

2.1.2.2 Point of Receipt -POR (Correctable) – valid Point of Receipt for scheduled Transmission Reservation.

2.1.2.3 Point of Delivery - POD (Correctable) – valid Point of Delivery for scheduled Transmission Reservation.

2.1.2.4 Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.

2.1.2.5 Scheduling Entity(ies) (Correctable) – entities that are physically scheduling interchange on behalf of the TRANSMISSION PROVIDER in order to provide wheeling services.

2.1.2.6 Loss Provision Information (Required) (Correctable)– Information describing the manner in which losses are accounted for. Losses will either be paid back In-Kind or Financially.

2.1.2.7 Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.

2.1.2.8 POR and POD Profiles (Required) – schedule of Energy Flow imported at the Point of Receipt and Exported at the Point of Delivery.

2.1.2.9 Transmission Reservation Number(s) (Required) (Correctable) – reference to a particular transmission reservation being used to provide transmission capacity to support the Interchange being described.

2.1.2.9.1 Transmission Product (Required) (Correctable) – Specifies the NERC Priority.

2.1.2.9.2 Transmission Customer (Required) (Correctable) – identifies the entity that purchased and holds the transmission reservation being presented for use.

2.1.2.9.3 Transmission Reservation Profile (Required) - information describing the transmission reservation commitment associated with the TRANSMISSION PROVIDER.

2.1.3. Load (Required) – set of data describing the physical and contractual characteristics of the energy sink.

2.1.3.1. Resource Service Point (Required) – the physical point at which the energy is being consumed. This may vary in granularity, dependent on local business practices.

2.1.3.2. Contract Number(s) (Correctable) – reference to a schedule or agreement entered into by the Load Serving Entity and the Load and/or Distributor.

2.1.3.3. Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.

2.1.3.4. Energy Profile (Required) – energy to be consumed by the load for this RFI.

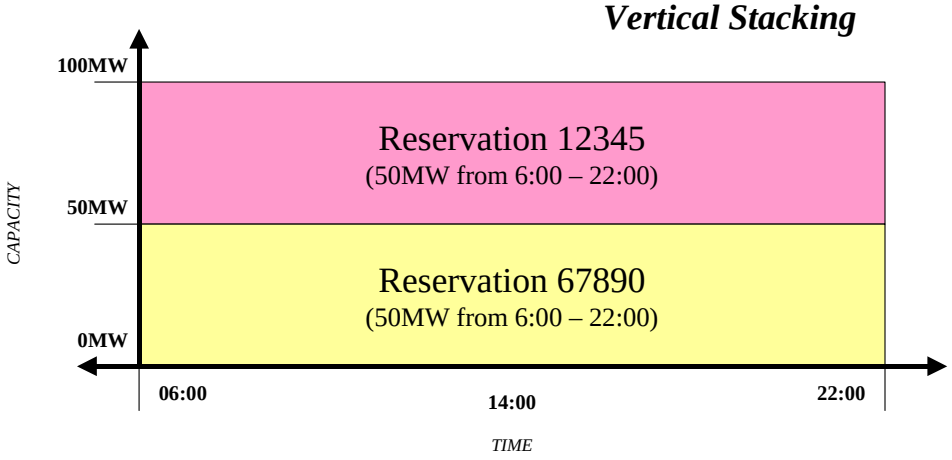
Using Multiple Transmission Reservations to Support a Single Leg of an Interchange

The use of multiple transmission reservations to support a single leg of an RFI is known as transmission **stacking**. There are two types of transmission stacking:

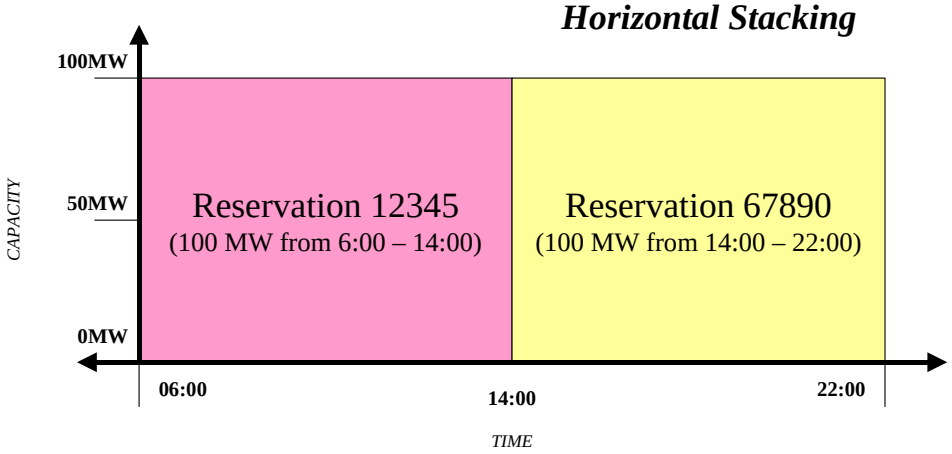
- Vertical stacking, in which a Transmission Customer combines multiple reservations to achieve a certain net level of transmission capacity, and
- Horizontal stacking, in which a Transmission Customer combines multiple reservations to achieve a certain transmission capacity coverage over time.

The following diagrams illustrate these concepts more fully. In both cases, the assumed need is 100 MW of transmission capacity for hours 06:00 through 22:00.

Vertical Stacking



Horizontal Stacking



Should a customer elect to utilize stacking, including any combination of the two stacking types, to support their RFI, they must understand the following requirements:

- Stacks MUST be described through fully qualified profiles for each reservation being used
- At no point may the coverage described by the stack be less than the transmission capacity needed for the RFI's energy flow

B. Market-Related Profile Modifications (Market Adjustment)

Profile Modifications are changes to a RFI's energy profile based on market desires. Such modifications must be presented to those entities that are responsible for the implementation of the modification in order that they may **evaluate** the RFI and determine whether or not the modification can be implemented. The following information must be used to describe such a modification.

- The RFI being modified
- All necessary profile changes to set the transmission capacity or energy flow to the desired levels during the appropriate hours (including the specification of new reservations to support the request, if necessary), and
- Contact information for the person that initiated the modification.

NAESB RFI Submission and Response Timetables

Document Subsections

C. Eastern Interconnection – New Interchanges
D. Western Interconnection – New Interchanges
E. Interchange Corrections
F. Interchange Modifications

A. Eastern Interconnection – New Interchanges

The table below represents the recommended business practices for RFI submission deadline to the Reliability Entities+ within the Eastern Interconnection. These are default requirements; some regulatory or provincially approved provider practices may have requirements that are more stringent. Under these instances, the more restrictive criteria shall be adhered to.

Table 1: Eastern Interconnection – Timing Requirements

Interchange Duration	Submit Deadline to Reliability Entities * +	Actual RFI Submission Time	Approval Entity Assessment Time	Time to Start of Interchange
Less than 24 Hours	20 Minutes prior to start	≤1 Hour prior to start	≤ 10 Minutes from tag receipt	≥ 10 Min
		>1 to <4 hours prior to start	≤20 Minutes from tag receipt	≥ 40 Min
		≥ 4 Hours prior to start	≤ 2 Hours from tag receipt	≥ 2 Hours
24 Hours or longer	4 Hours prior to start	Any	≤ 2 Hours from tag receipt	≥ 2 Hours
*Start time references are for start of the INTERCHANGE not the start of the ramp. + Includes BA, RA, TSP				

RFI submission timing requirements are based on the duration of the INTERCHANGE. RFIs representing INTERCHANGES that run for less that one day (24 hours) must be submitted at least 20 minutes prior to the start of the INTERCHANGE (excluding ramp time). RFIs representing INTERCHANGES running for one day or more (24 hours or more) must be submitted at least four hours prior to the start. RFIs submitted that meet these requirements shall be considered "on-time" by the E-Tag system and may be granted conditional approval. RFIs submitted that do not meet these requirements shall be

considered “late” by the E-Tag system, and consequently will be denied if not explicitly approved by all parties.
The E-Tag system accepts tags with a start time up to one hour prior to the current time. Tags with a start time older than one hour will be rejected as invalid. This one-hour window shall be used to submit tags to document emergency actions taken to mitigate an OPERATING SECURITY LIMIT violation (Policy 3, Section A 2.4.1). This provision shall not be used to schedule INTERCHANGES without the proper tag (Policy 3, Section A 6.1).
RFI assessment timing requirements are based on the submission time of the RFI, as well as the duration. Hourly RFIs submitted one hour or less prior to start must be evaluated in ten minutes. Hourly RFIs submitted more than one hour but less than four hours prior to start must be evaluated in 20 minutes. RFIs with duration of less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. RFIs with duration of 24 hours or more must be evaluated in two hours.

Timing Requirements for Reallocation when in a TLR Event

During a NERC TLR event, INTERCHANGES may be submitted to replace existing INTERCHANGES with a lower transmission priority. The new INTERCHANGE RFI must be received by the Interchange Distribution Calculator no later than 35 minutes prior to the top of the hour to allow time for RELIABILITY COORDINATOR to assess the impact of reallocation.

B. Western Interconnection – New Interchanges

The tables below represent the recommended business practices for RFI submission deadlines to the Reliability Entities within the Western Interconnection. These are default requirements. The tables describe the various minimum submission and assessment timing requirements.

Table 2: Western Interconnection – Timing Requirements

Interchange Start/Submittal Time	Submit Deadline to Reliability Entities * +	Actual RFI Submission Time*	Approval Entity Assessment Time	Approval/Denial Notes	Time to Start of Interchange*
Start 00:00 next day or beyond when submitted prior to 18:00 of the current day	**15:00 day prior to start**	**Any**	**3 hours**	**Passive Approval if submitted before deadline, else Passive Denial. Deferred denial**	**≥ 6 Hours**

Start 00:00 next day and submitted between 18:00 and 23:59:59 on day prior to start – OR – start within current day		**≥ 4 Hours prior to start**	**2 Hours from RFI receipt**	**Passive Approval Deferred denial**	**≥ 2 Hours**
		<4 Hours to ≥1 Hour prior to start	**20 minutes from RFI receipt**	**Passive Approval Deferred denial**	**≥ 40 Min**
		<1 hour to ≥30 minutes prior to start	**10 minutes from RFI receipt**	**Passive Approval Deferred denial**	**≥ 20 Min**
		<30 minutes to ≥20 minutes prior to start	**10 minutes from RFI receipt**	**Passive Approval Deferred denial**	**≥ 10 Min**
	20 minutes prior to start	**<20 minutes prior to start**	**5 minutes from RFI receipt**	**Passive Denial. Deferred denial**	**Submission time minus maximum time of 5 minutes**

Notes/Clarification:

1. **All clock times are in PPT.**
2. **RFI falling under the criteria in yellow are deemed pre-schedule requests.**
3. **RFI falling under the criteria in green are deemed real-time requests.**
4. **Pre-schedule requests submitted between 15:00 and 18:00 will be assigned LATE composite status.**
5. **Real-time requests submitted after 20 minutes prior to the start of the Interchange will be assigned LATE composite status.**

***Start-time references are for start of the Interchange, not the start of the ramp.**

+ Includes BA, RA, TSP

RFI submission timing requirements are based on the type and duration of the INTERCHANGE. RFIs representing INTERCHANGES that run for less that one day (24 hours) within the current day must be submitted at least 30 minutes prior to the start of the INTERCHANGE (excluding ramp time). RFIs representing INTERCHANGES that are pre-scheduled to start the next day must be submitted by 1500 PST the day prior to the day the INTERCHANGE is to start. RFIs submitted that meet these requirements shall be considered "on-time" by the E-Tag system and may be granted conditional approval. RFIs submitted that do not meet these requirements shall be considered "late" by the E-Tag system, and consequently will be denied if not explicitly approved by all parties. The E-Tag system accepts tags with a start time up to one hour prior to the current time. RFIs with a start time older than one hour will be rejected as invalid. This one-hour window shall be used to submit RFIs to document emergency actions taken to mitigate an

OPERATING SECURITY LIMIT violation (Policy 3, Section A 2.4.1). This provision shall not be used to schedule INTERCHANGES without the proper RFI (Policy 3, Section A 6.1). RFI assessment timing requirements are based on the submission time of the RFI, as well as the duration. Hourly RFIs submitted one hour or less prior to start must be evaluated in ten minutes. Hourly RFIs submitted more than one hour but less than four hours prior to start must be evaluated in 20 minutes. RFIs with a duration of less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. RFIs submitted for pre-scheduled service starting the next day or a future day must be evaluated in three hours.

C. Interchange Corrections

INTERCHANGE Corrections may be provided by the PSE to the IA to replace non-reliability data listed in a RFI. As each correction is received, the Evaluation Time of the INTERCHANGE will extend, based on the following rules:

- Each correction shall extend the evaluation time by ten minutes
- At no time can the evaluation time be extended past the start time of the INTERCHANGE.
- Each correction shall reset the approval status of those entities affected by the correction
- The segment or segments corrected will be eligible for passive approval if the correction is received within the timelines specified below, except in the case where the INTERCHANGE has already been set for passive denial. The segment or segments corrected will be subject to passive denial if the correction is not received within the timelines specified below. At no point may a INTERCHANGE segment already under Passive Denial constraints be returned to Passive Approval eligibility.

Table 3: Correction Submission Requirements*

Eastern Interconnection	Western Interconnection
20 minutes prior to start	30 minutes prior to start
*Start time references are for start of the Interchange not the start of the ramp.	

D. Interchange Modifications

Market-initiated modifications and other INTERCHANGE modifications that affect energy profiles must be received by and evaluated within certain times. The following tables describe the submission and evaluation requirements for such changes.

Modification requests received by the deadlines specified below shall be considered "on time," and are eligible for active Approval. Modification requests received past the deadlines shall be considered "late," and are considered denied unless explicitly approved by all parties.

Table 4: Eastern Interconnection – Modifications

Modification Type	Requestor Submission Deadline***	Actual Submission Time***	Evaluation Time
Reliability (Curtailments or Reloads)	20 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
Market – Committed Transmission Reservation(s) Reductions	N/A	N/A	N/A
Market – Committed Transmission Reservation(s) Increases, Energy Reductions, Energy Increases*	20 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
***Start time references are for start of the Interchange not the start of the ramp.			

Table 5: Western Interconnection – Modifications

Modification Type	Requestor Submission Deadline***	Actual Submission Time***	Evaluation Time
Reliability (Curtailments or Reloads)	25 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
Market – Committed Transmission Reservation(s) Reductions	N/A	N/A	N/A
Market – Committed Transmission Reservation(s) Increases, Energy Reductions, Energy Increases*	25 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
***Start time references are for start of the Interchange not the start of the ramp.			

*See Special Exception for Cancellations below

**If received after deadline, requires active approval or will be passively denied

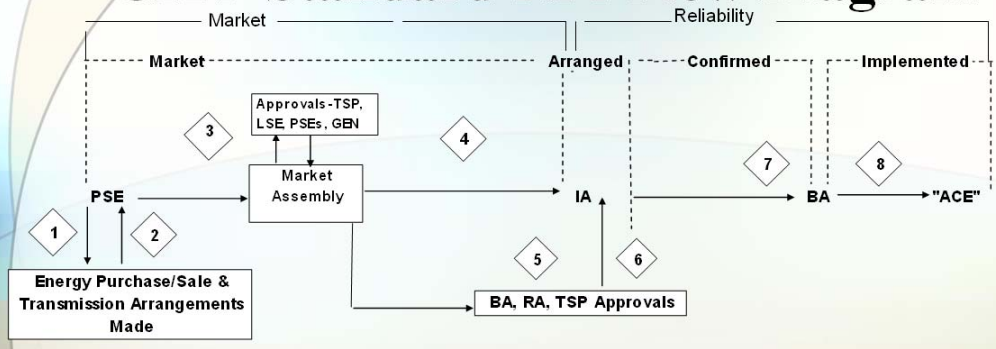
Special Exception for Cancellations

A cancellation is defined as setting both committed transmission reservation(s) and energy flow to zero for the duration of the INTERCHANGE **prior** to the start of a INTERCHANGE but **following** that INTERCHANGES approval. In the event that a PSE elects to cancel a INTERCHANGE, the following timelines should be utilized:

Table 6: Special Exception for Cancellations Submission and Evaluation Timing

Region	Submission Deadline*	Evaluation Time
Eastern Interconnection	**15 minutes prior to Interchange start**	**If received by deadline, no evaluation required. Request is automatically approved.**
		If not received by deadline, request is not eligible for Special Exception for Cancellations, and must be processed normally.
Western Interconnection	**20 minutes prior to Interchange start**	**If received by deadline, no evaluation required. Request is automatically approved.**
		If not by deadline, request is not eligible for Special Exception for Cancellations, and must be processed normally.
***Start time references are for start of the Interchange not the start of the ramp.**		

CIBP Standard RFI Flow Diagram



- **1 & 2** - All energy purchase/sale & transmission service arrangements are performed.
- **3** - Market approvals/verifications by Market Assembly Function.
- **4** - Submission of RFI by Market Assembly Function to IA. RFI includes reliability data (required) and business information.
- **5** - Market Assembly Function sends RFI request to reliability Approval Entities. Steps 4 & 5 take place at the same time.
- **6** – IA receives approvals/denials from reliability Approval Entities.
- **7** - IA sends approved and confirmed RFI to BA for implementation.
- **8** - BA enters data into ACE equation.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
Section A			
1. INTERCHANGE TRANSACTION arrangements. The PURCHASING-SELLING ENTITY shall arrange for all Transmission Services, tagging, and contact personnel for each INTERCHANGE TRANSACTION to which it is a party	None	**CI Standard** under Req 1.0, 1.1, 2.0,9.0	Deal arrangements are not part of the new Standard
1.1 The PURCHASING-SELLING ENTITY shall arrange the Transmission Services necessary for the receipt, transfer, and delivery of the TRANSACTION.	None	**CI Standard** under Req 1.1	Deal arrangements are not part of the new Standard
1.2 Transmission services. **Tagging.** The PURCHASING-SELLING ENTITY serving the load shall be responsible for providing the INTERCHANGE TRANSACTION tag. (Note: 1. Any PSE may provide the tag; however, the load-serving PSE is responsible for ensuring that a single tag is provided. 2. If a PSE is not involved in the TRANSACTION, such as delivery from a jointly owned generator, then the SINK CONTROL AREA is responsible for providing the tag. PSEs must provide tags for all INTERCHANGE TRANSACTIONS in accordance with Requirement 2.)	None	**CI Standard** refers to "tag" as it is called today as the "RAI", Request for Arranged Interchange.	This requirement is dependent on the future of the IDC . Providing the tag is equivalent to providing the information to IDC.
1.3Contact personnel. Each PURCHASING-SELLING ENTITY with title to an INTERCHANGE TRANSACTION must have, or arrange to have, personnel	None	**1.2 is covered in the NAESB CI Standard under Req 9.0**	In the new standard the PSE is notified by the IA of the approval of the requested interchange but is not

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
directly and immediately available for notification of INTERCHANGE TRANSACTION changes. These personnel shall be available from the time that title to the INTERCHANGE TRANSACTION is acquired until the INTERCHANGE TRANSACTION has been completed.			required to take any action.
1.4 E-Tag monitoring. CONTROL AREAS, TRANSMISSION PROVIDERS, and PURCHASING-SELLING ENTITIES who are responsible for a tagged TRANSACTION shall have facilities to receive unsolicited notification from the Tag Authority of changes in the status of a tag with which the user is a participant.	The parallel to this requirement would be the requirement to have facilities to receive interchange information from the IA(s). This requirement is implied in Coordinate Interchange Standard (measure 403) for the TSP and BA.	**1.4 is covered for the PSE in the NAESB CI Std. The TSP and CA/BA are required to respond (but does not require the people or facilities to continuously monitor) to requests by the IA in the NERC CI Std .**	The tag authority is not in the functional model
2.1 Application to TRANSACTIONS. All INTERCHANGE TRANSACTIONS and certain INTERCHANGE SCHEDULES shall be tagged. In addition, intra-CONTROL AREA transfers using Point-to-Point Transmission Service[1] shall be tagged. This includes: • INTERCHANGE TRANSACTIONS (those that are between CONTROL AREAS). • TRANSACTIONS that are entirely within a CONTROL AREA.	**Standard Reference-** Coordinate Interchange Standard (measure 401) The Balancing Authority shall provide evidence that Implemented Interchange matches Confirmed Interchange as submitted by the Interchange Authority.	None	There is no requirement for tagging in the standard. The big question is will IDC still be in existence? If so will the IA provide the IDC with the appropriate information?

[1] This includes all "grandfathered" and other "non-888" Point-to-Point Transmission Service

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
• DYNAMIC INTERCHANGE SCHEDULES (tagged at the expected average MW profile for each hour). (Note: a change in the hourly energy profile of 25% or more requires a revised tag.) • INTERCHANGE TRANSACTIONS for bilateral INADVERTENT INTERCHANGE payback (tagged by the SINK CONTROL AREA). • INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins (tagged by the SINK CONTROL AREA). **[See also, Policy 1E2 and 2.1, "Disturbance Control Standard"]**			
2.2 Parties to whom the complete tag is provided. The tag, including all updates and notifications, shall be provided to the following entities: • Generation Providing Entity • Generation CONTROL AREA • TRANSMISSION PROVIDERS • Transmission Customers	**Standard Reference-** There is no requirement for a tag. However the Coordinate Interchange Standard (measure 404) requires: The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in	**1.7 is covered under the NAESB CI Std:** Requires the IA to provide everyone involved in transaction a copy of the RAI (Tag in a CA paradigm).	

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
• Scheduling Entities (INTERMEDIARY CONTROL AREAS) • Intermediate PURCHASING-SELLING ENTITIES (Title-Holders) • Load CONTROL AREA • LOAD-SERVING ENTITY • Market Redispatch Notification Entities (if specified) • Security Analysis Services	the Interchange.		
2.3 **Method of transmitting the tag.** The PURCHASING-SELLING ENTITY shall submit the INTERCHANGE TRANSACTION tag in the format established by each INTERCONNECTION **2.3.1Tags for INTERCHANGE TRANSACTIONS that cross INTERCONNECTION boundaries.** Procedures are found in **Appendix 3A2, "Tagging Across Interconnection Boundaries."**	None	**1.7.1 is covered under the NAESB CI Std** (in the RAI Data table) under Req 3.0 for the type of data required and requests the data to be electronically. Does not specify a particular format.	Format will not be part of a Reliability Standard. Note Appendix 3A2 needs to be updated to reflect the use of tags in the Western Interconnection
2.4 INTERCHANGE TRANSACTION submission time. To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTIONS shall be submitted as specified in **Appendix 3A1, "Tag Submission and Response Timetable."**	None	**This is covered in the NAESB CI Std** and is called the RAI submission and Response timetable for the Market period and the Arranged Interchange Response timetable for the Reliability period.	There will not be any timing requirements in the reliability standard. If the tag is not submitted in time the deal does not happen.
2.4.1Exception for security	None	**Not covered in the**	Changes for reliability

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
reasons. Exception to the submission time requirements in Section 0 is allowed if immediate changes to the INTERCHANGE TRANSACTIONS are required to mitigate an OPERATING SECURITY LIMIT violation. The tag may be submitted after the emergency TRANSACTION has been implemented but no later than 60 minutes.		**NAESB Standards.** May want to consider in a NERC Std.	reasons is addressed in the measures for requirement 402 of the Coordinate Interchange Standard, however there are not any timing requirements.
2.5 Confirmation of tag receipt. Confirmation of tag receipt shall be provided to the PURCHASING-SELLING ENTITY who submitted the tag in accordance with INTERCONNECTION tagging practices. **["E-Tag Reference Document"]**	None		Not in the coordinate interchange standard. If the interchange is confirmed the PSE will be notified by the IA.
2.6 Tag acceptance. An INTERCHANGE TRANSACTION tag shall be accepted if all required information is valid and provided in accordance with the tagging specifications in Requirement 2.	Coordinate Interchange Standard Requirement 403. The Reliability Authority, Balancing Authority and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange by acknowledging that the Arranged Interchange is acceptable and reliable with respect to their functional responsibilities	**Covered in the NAESB CI Std** under Requirement 4.0	The Standard does not require acceptance but the criteria for review is defined to be reliability related.
3. INTERCHANGE TRANSACTION tag receipt verification. The SINK	Coordinate Interchange Standard Requirement 402. The IA confirms		

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
CONTROL AREA shall verify the receipt of each INTERCHANGE TRANSACTION tag with the TRANSMISSION PROVIDERS, and CONTROL AREAS on the SCHEDULING PATH before the INTERCHANGE TRANSACTION is implemented.	the interchange with the BAs and TSPs.		
4. INTERCHANGE TRANSACTION assessment. Generation Providing Entities, LOAD SERVING ENTITIES, TRANSMISSION PROVIDERS, CONTROL AREAS on the SCHEDULING PATH, and other operating entities responsible for operational security shall be responsible for assessing and "approving" or "denying" INTERCHANGE TRANSACTIONS as requested by PURCHASING-SELLING ENTITIES, based on established reliability criteria and adequacy of INTERCONNECTED OPERATIONS SERVICES and transmission rights as well as the reasonableness of the INTERCHANGE TRANSACTION tag. GENERATION PROVIDING ENTITIES and LOAD SERVING ENTITIES may elect to defer their approval responsibility to their HOST CONTROL AREA. This assessment shall include the following: **The CONTROL AREA assesses:** • TRANSACTION start and end time • Energy profile (ability of generation maneuverability to accommodate) • SCHEDULING PATH (proper	Coordinate Interchange Standard Requirement 403: The Reliability Authority, Balancing Authority and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange by acknowledging that the Arranged Interchange is acceptable and reliable with respect to their functional responsibilities.	**The NAESB CI Std Req** 4.0 and 5.0 addresses this.	Loss Accounting is not addressed.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
connectivity of ADJACENT CONTROL AREAS) **The TRANSMISSION PROVIDER assesses:** • Valid OASIS reservation number or transmission contract identifier • Proper transmission priority • Energy profile accommodation (does energy profile fit OASIS reservation?) • OASIS reservation accommodation of all INTERCHANGE TRANSACTIONS • Loss accounting **The Generation Providing Entity and LOAD-SERVING ENTITY assess:** • TRANSACTION is valid representation of contractually agreed upon energy delivery			
4.1 Tag corrections. During the CONTROL AREAS' and TRANSMISSION PROVIDERS' Assessment Time, the PURCHASING-SELLING ENTITY who submitted the tag may elect to submit a tag correction. Tag corrections are changes to an existing tag that do not affect the reliability impacts of the INTERCHANGE TRANSACTION; therefore, tag corrections do not require the complete re-assessment of the tag by all CONTROL AREAS and	None	**The NAESB CI Std Req** 6.0, 8.0, 8.1, 8.1.2, 8.2 and 5.0 addresses this for Market changes.	PSE adjust is a market function. Any market changes of approved interchange will follow the same process as an initial interchange request.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
TRANSMISSION PROVIDERS on the SCHEDULING PATH, or the completion and submission of a new tag by the PURCHASING-SELLING ENTITY. The SINK CONTROL AREA shall notify all CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH of the correction, and specifically alert those entities for which a correction has impact. Entities who are impacted by the correction will have an opportunity to reevaluate the tag status. The timing requirements for corrections are found in **Appendix 3A1, "Tag Submission and Response Timetable**." Tag items that may be corrected are found in **Appendix 3A4, "Required Tag Data."** A description of those entities who may correct an INTERCHANGE TRANSACTION tag is found in **Appendix 3D, "Transaction Tag Actions." [See Appendix 3A1 Subsection C, Interchange Transaction Corrections]**			
5. INTERCHANGE TRANSACTION approval or denial. Each CONTROL AREA or TRANSMISSION PROVIDER on the SCHEDULING PATH responsible for assessing and "approving" or "denying" the INTERCHANGE TRANSACTION shall notify the SINK CONTROL AREA. The SINK CONTROL AREA in turn notifies the PURCHASING-SELLING ENTITY	Included in the Coordinate Interchange Standard Requirement 402 and 404. This process is the responsibility of the IA. The IA gathers approvals from the BA, RA and TSP. The IA communicates approval or denial to all entities involved.	**The Naesb CI Std** addresses this in Req. 4.0 and 5.0. Timing Requirements are addressed in Req. 4.1 for PSE timing and timing during the Reliability period are covered under 5.0	

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
who submitted the INTERCHANGE TRANSACTION tag, plus all other CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH. Assessment timing requirements are found in **Appendix 3A1, "Tag Submission and Response Timetable."** A description of those entities who may approve or deny an INTERCHANGE TRANSACTION is found in **Appendix 3D, "Transaction Tag Actions."**			
5.1 INTERCHANGE TRANSACTION denial. If denied, this notification shall include the reason for the denial.	None	**Covered under NAESB CI** Std under Req. 5.1	
5.2 INTERCHANGE TRANSACTION approval. The INTERCHANGE TRANSACTION is considered approved if the PURCHASING-SELLING ENTITY who submitted the INTERCHANGE TRANSACTION tag has received confirmation of tag receipt and has not been notified that the transaction is denied.	Included in the Coordinate Interchange Standard Requirement 404: The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange.	**Also covered in the NAESB Std** under Req. 5.0	
6. Responsibility for INTERCHANGE TRANSACTION implementation. The SINK CONTROL AREA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy	Coordinate Interchange Standard Requirement 401: The Balancing Authority shall provide evidence that Implemented Interchange matches		

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of all CONTROL AREAS on the SCHEDULING PATH in accordance with Policy 3B. **6.1 Tag requirements for INTERCHANGE TRANSACTION implementation.** The CONTROL AREA shall implement only those INTERCHANGE TRANSACTIONS that: • Have been tagged in accordance with Requirement 2 above, or, • Are exempt from tagging in accordance with Requirement 1.13 above.	Confirmed Interchange as submitted by the Interchange Authority.		
7. Tag requirements after curtailment has ended. After the curtailment of a TRANSACTION has ended, the INTERCHANGE TRANSACTION'S energy profile will return to the originally requested level unless otherwise specified by the PURCHASING-SELLING ENTITY. [See **Interchange Transaction Reallocation During TLR Levels 3a and 5a Reference Document, Version 1 Draft 6**]	None	**Not covered in the NAESB Standards.** May want to consider in a NERC Std.	Section 402 addresses reliability related changes but does not address actions when the reliability change is no longer necessary. This should be addressed somewhere.
8.Confidentiality of information. RELIABILITY COORDINATORS, CONTROL AREAS, TRANSMISSION PROVIDERS, PURCHASING-	None	Currently not covered in the **NAESB CI Std** Could it be covered in the Certification SARs.	This is a FERC issue.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
SELLING ENTITIES, and entities serving as tag agents or service providers as provided in the "**E-Tag Reference Document"** shall not disclose INTERCHANGE TRANSACTION information to any PURCHASING-SELLING ENTITY except as provided for in Requirement 2.2 above, "**Parties to whom the complete tag is provided.**"			
Section B			
1. CONTROL AREAS must be adjacent. INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS.	None	**Not covered in the NAESB CI Std.**	This is not required in the functional model
2. Sharing INTERCHANGE SCHEDULES details. The SENDING CONTROL AREA and RECEIVING CONTROL AREA must provide the details of their INTERCHANGE SCHEDULES via the Interregional Security Network as specified in Policy 4.B.	Coordinate Interchange Standard Requirement 402. This is confirmed by the RA in the approval of interchange Coordinate Interchange Standard Requirement 404: The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange.	**Not covered in the NAESB CI Std.**	The RA will receive the Interchange information.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
3. Providing tags for approved TRANSACTIONS to the RELIABILITY COORDINATOR. The SINK CONTROL AREA shall provide its RELIABILITY COORDINATOR the information from the INTERCHANGE TRANSACTION tag electronically for each Approved INTERCHANGE TRANSACTION.	Coordinate Interchange Standard Requirement 404: The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange. Coordinate Interchange Standard Requirement 402. IA confirms that the RA has approved the interchange.	**Also covered in the Naesb Std under Req. 5.0**	
4. INTERCHANGE SCHEDULE confirmation and implementation. The RECEIVING CONTROL AREA is responsible for initiating the confirmation and implementation of the INTERCHANGE SCHEDULE with the SENDING CONTROL AREA. **4.1 INTERCHANGE SCHEDULE agreement**. The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall agree with each other on the: • INTERCHANGE SCHEDULE start and end time • Ramp start time and rate	Included in Coordinate Interchange Standard Requirement 402 measures.		The IA coordinates implementation of the interchange.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
• Energy profile This agreement shall be made before either the SENDING CONTROL AREA or RECEIVING CONTROL AREA makes any generation changes to implement the INTERCHANGE SCHEDULE.			
4.1.2 Operating reliability criteria. CONTROL AREAS shall operate such that INTERCHANGE SCHEDULES or schedule changes do not knowingly cause any other systems to violate established operating reliability criteria.	**Standard Reference-** Coordinate Interchange Standard Requirement 403: The Reliability Authority shall acknowledge that the interchange is acceptable and reliable with respect to its functional responsibilities.		
4.1.3 DC tie operator. SENDING CONTROL AREAS and RECEIVING CONTROL AREAS shall coordinate with any DC tie operators on the SCHEDULING PATH.	None		Coordinate Interchange Standard Requirement 402 requires a transmission reservation but does not require coordination with the DC tie operator
5. Maximum scheduled interchange. The maximum NET INTERCHANGE SCHEDULE between two CONTROL AREAS shall not exceed the lesser of the following: **5.1 Total capacity of facilities.** The total capacity of both the owned and arranged-for transmission facilities in service between the two CONTROL AREAS, or **5.2 Total Transfer**	**Standard Reference-** Coordinate Interchange Standard Requirement 403: The Transmission Service Provider shall acknowledge that the interchange is acceptable and reliable with respect to its functional responsibilities.		

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
Capability. The established network Total Transfer Capability (TTC) between the CONTROL AREAS, which considers other transmission facilities available to them under specific arrangements, and the overall physical constraints of the transmission network. Total Transfer Capability is defined in *Available Transfer Capability Definitions and Determination,* NERC, June 1996.			
Section D			
1. INTERCHANGE TRANSACTION modification for market-related issues. The PURCHASING-SELLING ENTITY that submitted an INTERCHANGE TRANSACTION tag may modify an INTERCHANGE TRANSACTION tag that is in progress or scheduled to be started**.** These modifications may be made due to changes in contracts, economic decisions, or other market-based influences. In cases where a Market Operator is serving as the source or sink for a TRANSACTION, then they shall have the right to effect changes to the energy flow as well (based on the results of the market clearing). **1.1 Increases.** The INTERCHANGE TRANSACTION tag's energy and/or committed transmission reservation(s) profile may be increased to reflect a desire to flow more energy or commit more transmission than	None	**Covered under the NAESB CI Std** under Req. 6.0, 8.0, 8.1, 8.1.2, 8.2	For the purpose of the Coordinate Interchange Standard any changes for market related purposes follow the same process as the initial request For interchange

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
originally requested. Necessary transmission must be either available from the earlier TRANSACTION or provided with the increase. **1.2 Extensions.** The INTERCHANGE TRANSACTION tag's energy profile may be extended to reflect a desire to flow energy during hours not previously specified. Necessary transmission capacity must be provided with the extension. **1.3 Reductions.** The INTERCHANGE TRANSACTION tag's energy and/or committed transmission reservation(s) profile may be reduced to reflect a desire to flow less energy or commit less transmission than originally requested. Reductions are used to indicate cancellations and terminations, as well as partial decreases. **Combinations of 1.1, 1.2, and 1.3 may be submitted concurrently.** **Coordination responsibilities of the PURCHASING-SELLING ENTITY.** The modification must be provided by the PURCHASING-SELLING ENTITY to the following INTERCHANGE TRANSACTION participants: • Generation Providing Entity • • • TRANSMISSIONCUSTOMERS • Scheduling Entities (INTERMEDIARY CONTROL			

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
AREAS) • Intermediate PURCHASING-SELLING ENTITIES (Title-holders) • • LOAD-SERVING ENTITY • Market Redispatch Notification Entities (if specified)			
1.6 INTERCHANGE TRANSACTION modification confirmation. Depending on the type of change, certain entities must evaluate and approve or deny the INTERCHANGE TRANSACTION modification. The following tables illustrate the entities required to evaluate the modification and the criteria they should use in their evaluation. All other entities will be notified of the request. Net Increases in Committed Transmission Reservations or changes in Loss Provision- TSP and DC Tie operator Net Decreases in Committed Transmission Reservations – TSP and DC tie operator Increases in Energy Flow- BA's , TSP's, RA and DC tie operator Decreases in Energy Flow- BA's , TSP's, RA and DC tie operator	**Standard Reference-** Included in Coordinate Interchange Standard Requirement 402 measures.	**Covered under NAESB CI Std** under Req. 8.1.2	
1.7 INTERCHANGE TRANSACTION modification and evaluation time. To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTION modifications shall be	None	**Covered under the NAESB CI Std** under Req. 4.1, 5.0	There will not be any timing requirements in the reliability standard. If the tag is not submitted in time the deal does not happen.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
requested and evaluated as specified in Section D of **Appendix 3A1, "Tag Submission and Evaluation Timetable."**			
2. INTERCHANGE TRANSACTION modification for reliability-related issues. A RELIABILITY AUTHORITY, TRANSMISSION PROVIDER, GENERATION CONTROL AREA, or LOAD CONTROL AREA may modify an INTERCHANGE TRANSACTION Tag that is in progress or scheduled to be started**.** These modifications may be made *only* due to TLR events (or other regional congestion management practices), Loss of Generation, or Loss of Load.	Included in Coordinate Interchange Standard Requirement 402 Measure vii (1): For a reliability related change requested by a Reliability Authority, no other entity approvals are required.		.
2.1 Assignment of coordination responsibilities during TLR events. At such times when TLR is required to ensure reliable operation of the electrical system, and the TLR requires holding or curtailing INTERCHANGE TRANSACTIONS, the LOAD CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags. See **Policy 9, Appendix 9C1 "Transmission Loading Relief Procedure."** **2.1.1 Reductions**. When a RELIABILITY AUTHORITY must curtail or hold an INTERCHANGE TRANSACTION to respect TRANSMISSION SERVICE reservation priorities or to mitigate potential or actual	Included in Coordinate Interchange Standard Requirement 402 Measure vii (1): For a reliability related change requested by a Reliability Authority, no other entity approvals are required.		The IA is responsible for the coordination of these actions

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
OPERATING SECURITY LIMIT violations, the RELIABILITY AUTHORITY shall inform the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag of the greatest reliable level at which the affected INTERCHANGE TRANSACTION may flow. **2.1.2 Reloads.** At such time as the TLR event allows for the reloading of the transaction, the RELIABILITY AUTHORITY shall inform the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag of the releasing of the INTERCHANGE TRANSACTION'S limit.			
2.2 Coordination when implementing other congestion management procedures. As a part of some local and regional congestion management and transmission line overload procedures, the TRANSMISSION PROVIDER is responsible for implementing curtailment of INTERCHANGE TRANSACTIONS. The TRANSMISSION PROVIDER may adjust the INTERCHANGE TRANSACTION tags as required to implement those local and regional congestion management or transmission overload relief procedures that have been approved by the Region(s) or NERC. **2.2.1 Reductions.** When a TRANSMISSION PROVIDER experiences the need to invoke a congestion management or transmission line overload procedure, it may use the	Included in Coordinate Interchange Standard Requirement 402 Measure vii (1): For a reliability related change requested by a Reliability Authority, no other entity approvals are required.		The transmission provider will notify the Reliability Coordinator of the need for a curtailment. The IA is responsible for the coordination of these actions

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
curtailment feature of E-Tag to inform the GENERATION CONTROL AREA and the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag of the greatest reliability limit at which the affected INTERCHANGE TRANSACTION may flow. **2.2.2 Reloads.** At such time as the need for the congestion management or transmission line overload relief procedure allows for the full or partial reloading of the transaction, the TRANSMISSION PROVIDER may use the reload feature of E-Tag to inform the GENERATION CONTROL AREA and the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag that the INTERCHANGE TRANSACTION'S reliability limit has changed.			
2.3 Assignment of coordination responsibilities during a loss of generation. At such times when a loss of generation necessitates curtailing INTERCHANGE TRANSACTIONS, the Generation CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags. **2.3.1 Reductions.** When a generation operator experiences a full or partial loss of generation, it shall notify the HOST CONTROL AREA (the generation CONTROL AREA for the INTERCHANGE TRANSACTION). The HOST CONTROL AREA contacts the	Included in Coordinate Interchange Standard Requirement 402 Measure vii (1): For a reliability related change requested by a Reliability Authority, no other entity approvals are required.		The BA will notify the Reliability Coordinator of the need for a curtailment. The IA is responsible for the coordination of these actions

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
Generation Providing Entity that is responsible for the generation. The Generation Providing Entity determines what schedule modifications need to be made and may request those modifications as market-based reductions, increases, or extensions (either via the Tag Author, or directly if the Entity is the Tag Author or a Market Operator). If the Generation Providing Entity does not resolve the condition, the HOST CONTROL AREA may at its discretion curtail INTERCHANGE TRANSACTIONS associated with the generation. **2.3.2 Reloads.** Upon return of the generation, the generator operator shall notify the HOST CONTROL AREA (the Generation CONTROL AREA for the INTERCHANGE TRANSACTION). The HOST CONTROL AREA contacts the Generation Providing Entity that is responsible for the generation. The Generation providing Entity determines what schedule modifications need to be made and may request those modifications as market-based reductions, increases, or extensions (either via the Tag Author, or directly if the Entity is the Tag Author or a Market Operator). The HOST CONTROL AREA must release the limits previously imposed on INTERCHANGE TRANSACTIONS associated with the generation (but not override any market-based reductions).			
2.4 Assignment of coordination	Included in Coordinate		

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
responsibilities during a loss of load. At such times when a loss of load necessitates curtailing INTERCHANGE TRANSACTIONS, the LOAD CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION Tags. **2.4.1 Reductions.** When a LOAD-SERVING ENTITY experiences a loss of load, it shall notify its HOST CONTROL AREA (the LOAD CONTROL AREA for the INTERCHANGE TRANSACTION) and determine what schedule modifications need to be made. The LOAD-SERVING ENTITY may request those modifications as market-based reductions, increases, or extensions (either via the Tag Author, or directly if the Entity is the Tag Author or a Market Operator). If the LOAD-SERVING ENTITY does not notify the HOST CONTROL AREA, the HOST CONTROL AREA may at its discretion curtail INTERCHANGE TRANSACTIONS associated with the load. **2.4.2 Reloads.** Upon return of the load, THE LOAD-SERVING ENTITY shall notify its HOST CONTROL AREA (the LOAD CONTROL AREA for the INTERCHANGE TRANSACTION) and determine what schedule modifications need to be made. The LOAD-SERVING ENTITY may request those modifications as market-based reductions, increases, or extensions (either via the Tag Author, or directly if the	Interchange Standard Requirement 402 Measure vii (1): For a reliability related change requested by a Reliability Authority, no other entity approvals are required.		The BA will notify the Reliability Coordinator of the need for a curtailment. The IA is responsible for the coordination of these actions

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
Entity is the Tag Author or a Market Operator). If the LOAD-SERVING ENTITY does not notify the HOST CONTROL AREA, the HOST CONTROL AREA must release the limits previously imposed on INTERCHANGE TRANSACTIONS associated with the load (but not override any market-based reductions).			
2.5 Coordination responsibilities of the requesting CONTROL AREA. The modification must be provided by the Requesting CONTROL AREA to the following INTERCHANGE TRANSACTION participants: Transmission Customers Scheduling Entities (INTERMEDIATE CONTROL AREAS) Intermediate PURCHASING-SELLING ENTITIES (Title-holders) LOAD-SERVING ENTITY Generation Providing Entity Generation CONTROL AREA TRANSMISSION PROVIDERS Load CONTROL AREA Market Redispatch Notification Entities (if specified) Security Analysis Services	Included in Coordinate Interchange Standard Requirement 404: The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange."	**Under the NAESB CI Std** under Req. 6.0	The IA will coordinate and notify all entities of changes.
2.6 INTERCHANGE TRANSACTION modification confirmation. Reliability-based	Included in Coordinate Interchange Standard Requirement 403:		

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
modifications must be evaluated and confirmed prior to implementation. The following table illustrates the entities required to evaluate and the criteria they should use in their evaluation. All other entities will be notified of the request. Generation Control Area- Energy profile (ability of generation to accommodate) DC Tie Operating Transmission Providers or Control Areas- Energy profile (ability of tie to accommodate) Load Control Area- Energy profile (ability of load to accommodate)	The Reliability Authority, Balancing Authority and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange by acknowledging that the Arranged Interchange is acceptable and reliable with respect to their functional responsibilities.		
2.7 INTERCHANGE TRANSACTION modification and evaluation time. To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTION modifications shall be requested and evaluated as specified in **Appendix 3A1, "Tag Submission and Evaluation Timetable."**	None	**Covered under NAESB CI Std** under Req. 4.1 and 5.0	There will not be any timing requirements in the reliability standard. If the tag is not submitted in time the deal does not happen.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
Section C			
1. INTERCHANGE SCHEDULE start and end time. INTERCHANGE SCHEDULES shall begin and end at a time agreed to by the SOURCE CONTROL AREA, SINK CONTROL AREA, and the INTERMEDIARY CONTROL AREAS. **2. Ramp start times.** CONTROL AREAS shall ramp the INTERCHANGE equally across the start and end times of the schedule. **3.Ramp duration.** CONTROL AREAS shall use the ramp duration established by their INTERCONNECTION as follows unless they agree otherwise: **3.1 INTERCHANGE SCHEDULES within the Eastern and ERCOT INTERCONNECTIONS.** ten-minute ramp duration. **3.2 INTERCHANGE SCHEDULES within the Western INTERCONNECTION.** 20-minute ramp duration. **3.3 INTERCHANGE SCHEDULES that cross an INTERCONNECTION boundary.** The CONTROL AREAS that implement INTERCHANGE SCHEDULES that cross an INTERCONNECTION boundary must use the same start time and ramp durations.	Included in Coordinate Interchange Standard Requirement 402 measures.	**Covered under NAESB CI Std** under Req. 12.0	The standard does provide or preclude standard ramp times for the Eastern and Western Interconnection.
3.4 Exceptions for Compliance with Disturbance Control Standard and Line Load Relief. Ramp durations for INTERCHANGE SCHEDULES implemented for compliance with NERC's Disturbance	None		The standard does not have a specific ramp requirement.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
Control Standard (recovery from a disturbance condition) and INTERCHANGE TRANSACTION curtailment in response to line loading relief procedures may be shorter, but must be identical for the SENDING CONTROL AREA and RECEIVING CONTROL AREA **[See also Policy1E2, "Generation Control Performance – Performance Standard."]**			
4. INTERCHANGE SCHEDULE accounting. Block accounting shall be used.	None	**Covered under NAESB CI Std** under Req. 10.0	

Item 6. Other Issues – Various Presenters

Background

The IA function – John Simonelli

NERC Reliability Functional Model – Version 2

Discuss “Interchange State” definitions and the Functional Model – Roman Carter

Discuss “Operating Authority Users Manual” for reliability and business standards – Al Boesch

Attachments

6a John Simonelli paper on the IA Function

6b Andy Rodriquez comment on John Simonelli’s paper

The first part of this document is an introduction that was presented to the Interchange Subcommittee. John Simonelli's paper follows this introduction.

NERC OC IA Function Discussion

During Mike Oatts presentation to the Operating Committee at its meeting in January 2004 on the CI Standard the OC gave the Interchange Subcommittee a charge to work on the transition to NERC's new reliability standards, and to specifically work on the physical implementation of the IA function as defined in the NERC Reliability Functional Model. Although the OC charge was not discussed at length, and was given on a high level, the charge to the subcommittee is to begin defining how the IA will communicate and interact between the other FM functions, and how the IA would be operationally structured.

The OC charge may be analogous to Policy 3 and Tagging, whereas the FM and Standards provide the "what" and OASIS II including electronic scheduling will define the how. The "how" being the communication, interaction, certification, registration, and the business practices needed to implement the new standards and business practices.

Before discussing how the IA function might be implemented, the subcommittee should characterize the transition to reliability standards. Define what needs to be arranged before the transition can be completed. The industry will not operate under, or transition to, the FM, as the FM is only defines a set of functions with associated tasks. The industry will transition to and operate under the new reliability standards and the NAESB business practices. The transition will be enabled when entities are certified and registered and the standards and business practices are in place.

As the subcommittee discusses the potential configurations of the IA, we should remain aware of the ESS's work on OASIS II, as OASIS II will include the market to IA communications.

Suggestions for discussion:

- What are the functional requirements and tasks for the IA function?
- How should the IA be structured? What are the advantages/drawbacks to having one IA, one IA per interconnection, or one IA per interchange?
- Could the functional requirements be handled much as the tagging authority operates today?
- Does the IA function simply handle a set of data, looks for yes/no answers, and does not make decisions beyond a yes/no? Does the IA perform discretionary functions? What does this tell us about the potential configuration of the IA?
- What tools are needed to operate as an IA? If the data set for the IA (and other reliability functions) is defined, would that data be included in OASIS II? Note: OASIS II will include electronic scheduling.
- How will the certification and registration of the FM functions take place? What standards are needed to begin operations under the new standards? Review the

current certification SAR for the IA function. Is the certification for the FM functions (especially the IA function) enough and sufficient?

Discussion by John Simonelli

Potential IA Functionality in the new FM

General

This document represents a "first cut" at addressing some of the nagging questions regarding the IA functionality and possible implementation strategies. The documents sole purpose is to provide a written starting point for more inclusive industry debate. In crafting this document particular attention was paid to maintaining or improving upon overall system reliability and continued use of legacy systems where applicable to save cost, reduce implementation time and minimize industry disruption. The discussion is based on:

- ⇒ The current understanding of the IA role in the functional model,
- ⇒ The preliminary NERC Coordinate Interchange Standards,
- ⇒ The preliminary NAESB Coordinate Interchange Business Practice Standards and,
- ⇒ The current industry utilization of E-Tagging, IDC and NERC Policy #3.

The IA function as defined today serves as a gateway between the business side and the reliability side of moving energy between BA's. At a very high level, the IA will gather balanced, agreed upon schedule requests from PSE's, perform a verification with all reliability parties involved in the approval of the submitted schedule request (RA, BA, TSP, etc.) and, eventually instruct BA's to implement the approved final schedules to affect the physical energy flow between BA's in real-time.

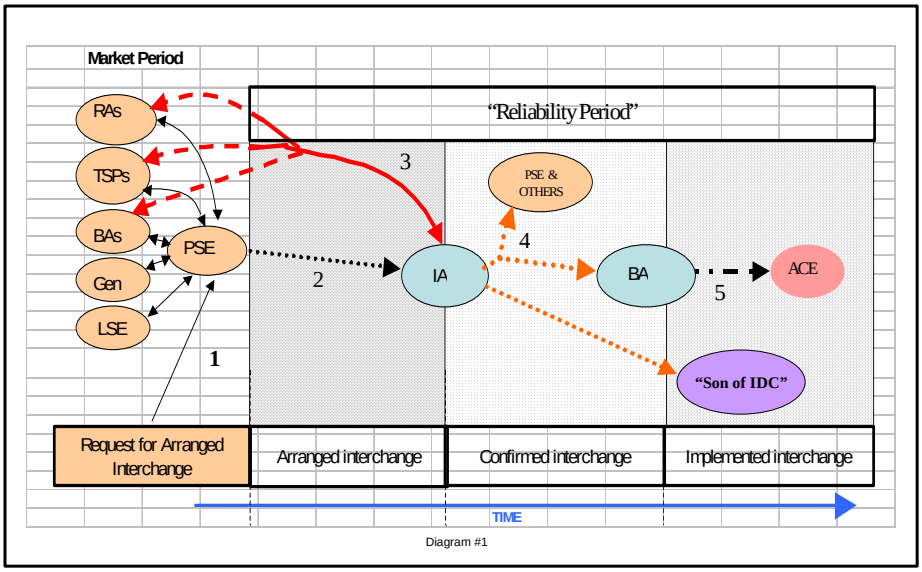


Diagram #1

It may be somewhat of a stretch but in looking at the current IA functionality one might conclude that it does not preclude the elimination of manual intervention, i.e., human handling. The functionality as currently defined may be accomplished by electronic means and a machine interface. A significant number of parallels exist between the IA functions as described and the current functionality embedded in the E-Tag Authority functionality. For the purposes of this discussion, it will be assumed that the IA can and will function in a manor similar to today's E-Tag Authority.

Single IA Concept

Two important issues must be addressed in the creation of an IA function, maintaining/improving reliability and increasing overall industry efficiency. From the standpoint of maintaining/improving reliability, the IA function is critical to moving energy between BAs. Accurate, timely coordination of interchange by the IA is crucial to system reliability. The IA must first accept all in-coming interchange requests from PSEs and then obtain active conformation from all affected reliability entities, RAs, BAs, TSPs, etc. The approval/denial of the transactions by any of these reliability entities must then be communicated back to the market for reconciliation/action upon denial or be communicated directly to the BAs for implementation upon approval. In looking at the possible permutations and combinations of RA, BA and TSP propagating across NERC under the FM, we believe the single, most efficient way to meet the reliability needs and expeditiously communicate the necessary data to all parties involved in physically moving energy between BAs is the formation of a single NERC-wide IA. Consider the complexity and multiple efforts if the reliability entities involved

are required to check out with multiple IAs. Consider the possibility for conflicts if each BA insists on using their "own" IA or there are allowances for many to many relationships between IAs and BAs. The shear volume of communications presents a risk to coordination within the industry.

Now consider increasing industry efficiency, let's look back at our experience with implementation of OASIS and E-Tagging. One of the biggest problems encountered was interoperability of systems due to variations in interpreting the desired functionality and the technical specifications. In a nutshell, everyone had a different interpretation of how it was supposed to work. Here again we believe the best way to eliminate this problem is to have a single NERC IA. This means one single entity will be responsible for the development of the necessary software functionality needed to implement the specifications required to fulfill the IA mandate under the FM and its supporting standards.

In summary the advantages of a single IA are:

- ⇒ Reduce the number of actual electronic communications that need to occur between all involved parties. The concept of an RA or BA having to deal with multiple IAs can only introduce unnecessary complexities, time delays and decreased flexibility. This will inherently improve reliability of the interconnected system,
- ⇒ Reduce response time between affected RA and BA entities when system emergencies arise that are directly affected by BA to BA transactions,
- ⇒ Allow for a single vendor to deal directly with those entities developing the functionality definitions and supporting technical specifications,
- ⇒ Force the vendor as a design requirement, to provide the most reliable and fully redundant system possible. Because of the critical nature of this functionality, meeting the highest possible industry availability standards is necessary regardless of the cost,
- ⇒ Allow for an expedited rollout of the IA by reducing the development, testing and startup effort by centralizing on a single vendor and,
- ⇒ Allow for greater accessibility by various industry backend systems because of standardization.

Market Arrangements

Based on the current understanding of the Functional Model, a single NERC-wide IA can be equated with today's E-Tag Authority. When one looks at diagram #1, there are three distinct time spans in a transactions life. The first being the market arrangement followed by an approval period and last, the actual implementation. To accomplish this, transaction data must be moved in an efficient and timely manor between all parties.

A PSE wishing to move energy from A to B will need an electronic system capable of submitting all necessary scheduling request information to the

appropriate RAs, BAs and TSPs for evaluation. This process must accommodate the unique regional requirements of both the physical and financial markets. As such, each RA, BA and TSP will have its own unique data requirements. After evaluation, each entity is required to return to the PSE a status of the request. Discrepancies will be reconciled by the PSE. This process of submitting a request, evaluating the request and returning a transaction status, is very similar to the current E-Tag process. NAESB should investigate using the current E-Tag platform and/or the future OASIS II to perform this function.

Approval Requirements

Once a PSE has obtained all necessary approvals on a requested transaction, e.g., all RA, BA and TSP entities have signed-off, the PSE must submit this balanced and agreed upon schedule to the IA. The data the IA receives must be sufficient in definition to allow all the reliability entities to authenticate the transaction and allow the BAs to implement the physical schedule.

As such, two levels of data need to be defined. The first is a definition of what data the individual reliability entities need to perform the final authentication, which may be entity specific. The data may have to allow for Regional variation and may not lend itself to standardization by either NERC or NAESB. Second, there needs to be a definition of what data the individual BAs need to physically implement the transaction. NERC should look to standardize this data set. NERC should also develop the communication protocols for moving the required data sets. Once the IA has obtained positive authentication, the final communication will occur to the BAs for implementation. This type of handshake can utilize the experience gained by the industry during the deployment of the existing E-tag functionality.

Implementation Issues

Once a BA has received the final authenticated schedules from the IA, they are required to implement the schedule within their individual BA ACE. There are, however, exceptations that might occur, such as:

- ⇒ A BA operating a financial market may find changes in system conditions causing prices to vary from those originally used to evaluate the transaction. In this case the BA may need to make a market adjustment to the transaction.
- ⇒ A BA may be unable to meet some of the original parameters of the transaction, such as ramp rate, due to changes in system conditions,
- ⇒ An RA may have a security violation occur that requires immediate reduction in BA to BA transfers,
- ⇒ Etc.

In these cases expedited communications with the IA is required. The IA must then forward the necessary schedule change/adjustment to all of the reliability entities and the submitting PSE. Having a single IA serve as the clearinghouse for all of this communication will help ensure reliability and improve market efficiencies.

John,

I think the concept of a single IA is a good one. While in general, I think that competitive software vendors in an open market is a good thing, I see the IA as a piece of critical infrastructure that must be closely controlled by the reliability folks. The IA simply cannot be allowed to fail, whether it is one vendor or a dozen. Sp we either need to have a significantly rigorous testing and certification of IAs, or have a single IA. Considering the likely cost of testing and certifying an IA, as well as the infrastructure costs to make them redundant, I think it is more prudent and cost effective to have just one, based on a competitive RFP process. This would ensure more efficient coordination and also aid in the "wide area view" tools that NERC seems to be moving toward.

As an idea to address the concerns with monopoly people are sure to bring up, perhaps the industry re-bids the IA function every 5 years? This will encourage competition. Of course, the down side is that you have to retest _everything_ if the vendor changes.

We will need to consider the legal aspects of this. I think we can legally say that the reliability concerns make this a natural monopoly (the same way there is only one IDC vendor), but we'll probably need to talk to NERC, NAESB, and our own internal legal departments to come up with an appropriate response to this issue.

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