North American Energy Standards Board

Executive Committee Meeting

Wholesale Electric Quadrant
Retail Gas Quadrant
Retail Electric Quadrant
Wholesale Gas Quadrant

May 4-6, 2004

Hosted by Florida Power and Light
Juno Beach, Florida

NORTH AMERICAN ENERGY STANDARDS BOARD

Executive Committee Meeting – WEQ, REQ, RGQ, WGQ Meeting Materials
May 4-6, 2004

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NORTH AMERICAN ENERGY STANDARDS BOARD
2004 WEQ Annual Plan
Approved by the Board of Directors December 4, 2003
Modified by the WEQ Executive Committee – February 24, 2004

	Item Description	Completion[1]	Assignment
1	**Develop business practices standards as needed to complement reliability standards**		
	(a) Develop business practice standards to support and complement NERC reliability standards, NERC policies and NERC standards authorization requests (SARs). Current NAESB activities underway to develop business practice standards that are supportive of this annual plan item are:		Standards Review Subcommittee (SRS)[2]
	i. Develop Inadvertent Interchange Payback Business Practices		BPS (IIPTF)
	ii. R03013 – Coordinate Interchange		ESS
	Status: Complete		SRS
	iii. R03014 – Coordinate Operations		SRS
	iv. R03017 -- Operate Within Limits		SRS
	v. Balance Resources and Demand		SRS
	vi. Facility Ratings		
	(b) Develop business practice standards applicable to the transition period from NERC policies to NERC reliability standards.		SRS/Various[3]
2	**Develop and Maintain Business Practice and Communication Standards for OASIS and Electronic Scheduling**		
	(a) Develop and/or maintain *business practice standards* as needed for OASIS and electronic scheduling including determining which, if any, ESC/OSC and other related industry groups' business practices and standards should be adopted as NAESB standards. Specific items to address include:		Electronic Scheduling Subcommittee (ESS)
	i. OASIS Phase IA (a) Adoption of business practices per FERC Order 638		ESS
	Status: Underway		

[1] Dates in the completion column are by end of the quarter for completion by the assigned committee. The dates do not necessarily mean that the standards are fully staffed so as to be implementable by the industry, and/or ratified by membership. If one item is completed earlier than planned, another item can begin earlier and possibly complete earlier than planned. There are no begin dates on the plan.

[2] The Standards Review Subcommittee scopes, identifies and defines the standards development work to be done to suppoer and complement NERC policies, SARs and NERC reliability standards. Once completed, the request, initial review document, scoping document and other work papers are transferred to the appropriate standards development subcommittee.

[3] The North American Electric Reliability Council Transition Team is responsible for establishing a plan to convert existing NERC policies to NERC reliability standards. Co-commitant with that conversion, NAESB will develop corresponding NAESB business practices. Michael Desselle, Rae McQuade and Charles Yeung are representatives of NAESB on the NERC Transition Team.

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	Item Description	Completion[1]	Assignment
	ii. OASIS Phase II per FERC ANOPR (Docket no. RM00-10-000) and subsequent orders 1. Adoption/maintenance of ESC use cases 2. Adoption/maintenance of Functional Requirements Document 3. Develop and Maintain business practices to support and implement the ESC use cases		ESS ITS ESS
	(b) Develop and/or maintain *standard communication protocols* and cybersecurity requirements as needed, including related industry standard communication protocols and cybersecurity requirements (i) OASIS Phase IA Adoption of S&CP version 1.4 Status: Underway (ii) OASIS Phase II per FERC ANOPR (Docket no. RM00-10-000) and subsequent orders Development of S&CP document (iii) NERC PKI initiative		Information Technology Subcommittee (ITS)
3	**Develop business practices standards to Improve the Current Operation of the Wholesale Electric Market** (a) Develop business practice standards needed to complement or assist specific seams mitigation efforts initiated by or coordinated with the NERC, the IRC, RTOs or ISOs, or other regional entities.		Seams/Various[4]
4	**Determine the need for and develop, if necessary, standard(s) requests for electric or gas standards required to provide additional flexibility in generation scheduling (including gas nominations).** Status: Underway		Gas Electric Coordination Task Force[5]

PROVISIONAL ITEMS

1	Develop standards and model business practices in accordance with FERC orders and rules issued in the SMD docket (RM01-12-000), or pursuant to Order Nos. 888 or 2000, or otherwise directed by the FERC.		

[4] The Seams Subcommittee scopes, identifies and defines the standards development work to be done related to the seams catalog. After seams catalog items are assigned to NAESB by the Joint Interface Committee, and the Seams Sucommittee completes its review and analysis, the request, initial review document, scoping document and other work papers are transferred to the appropriate standards development subcommittee.

[5] The Gas Electric Coordination Subcommittee is an ad hoc subcommittee comprised of participation by all four quadrants of NAESB to address the issues outlined in request number R03031, submitted by TVA and amended on November 20, 2003.

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	Item Description	Completion[1]	Assignment
2	Respond to FERC inquiries pertaining to business practice standard development and keep FERC informed on the nature and effectiveness of coordination activities with other standards setting organizations.		
3	Develop business practice standards related to FERC's forthcoming generation interconnection orders (large and small generators), in Docket Nos. RM02-01-000 and RM02-12-000.		
4	FERC Reporting of Electricity Prices		
5	Develop business practice standards as requested by the regional and state advisory groups.		
6	Develop electric purchase and sales contract.		

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Appendix
Comments Accompanying the Action Items and Provisional Items
For the 2004 Annual Plan Adopted by the Executive Committee – October 7, 2003

ACTION ITEMS:

1a The original 1(a) from the 2003 plan is implied and 1(b) and 1(c) have been rewritten as a part of this plan: 1(a) Apply NERC/NAESB MOU provisions in reviewing proposed reliability standards for their business practice implications, 1(b) Review existing NERC reliability policies and standards for their business practice implications, 1(c) Review each of the SARs in light of the NERC/NAESB MOU.

1b This is a new item that reflects the recent NERC decision to create Transition team. NAESB has been asked to join the Transition Team which is led by Gerry Cauley. NAESB members on the team are Charles Yeung, Rae McQuade and Michael Desselle.

2a The Information Technology Subcommittee has been formed and is currently reviewing existing lists of enhancements for OASIS 1A and OASIS 2. A NAESB Electronic Scheduling Subcommittee was created but is inactive awaiting input from the existing ESC industry group

2b The PKI request R03007 has been assigned to the NAESB WEQ to be addressed which is a portion of this annual plan item.

This item also corresponds to the 2003 WEQ Annual Plan item 4(h) Review activities of NERC CIPAG in light of NERC-NAESB MOU regarding cyber security requirements for their business practice and system communication standards implications.

3a A seams catalog is under development now and will identify many of the items to be included under this action item. This item was originally numbered item 4 in the 2003 WEQ Annual Plan. Several items were deleted, and will be added back to the plan if they are requested through the comments or meetings on the plan and the requesters indicate a willingness to participate in the standards development effort or in the drafting effort. The items removed from the 2003 plan are: 4(a) Establish a standardized electric trading day; 4(b). Identify and develop business practices on the public dissemination of market information.

Other items from the 2003 WEQ Annual Plan were reordered and renamed such as: 4(d) Develop business standards as necessary to resolve seams issues between ISOs and RTOs; 4(c) Establish standard business practices relating to: i) Definition and treatment of firm/nonfirm power; ii) Definition and treatment of firm/nonfirm transmission; iii) Provision of reserves for transactions across multiple control areas, 4(e) Develop standards for data requirements, data exchange and scheduling of day-ahead and real-time bilateral markets; and 4(h) Review activities of NERC CIPAG in light of NERC-NAESB MOU regarding cyber security requirements for their business practice and system communication standards implications.

Some items on the 2003 WEQ Annual Plan were considered assumed in each of the action items, so they were not specifically highlighted as a separate action item, such as : 4(f) Examine business practices and definitions currently in use to determine applicability on a North American basis and 4(g) Catalogue, assess and prioritize existing “standards” that have significant business practice implications.

4 This is a new item, not in the 2003 plan. It was added at the August 5 Executive Committee meeting.

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PROVISIONAL ITEMS:

1 These items (originally items 3 and 7 of the 2003 Annual Plan) were reclassified as provisional and will be acted upon as such FERC actions are taken.

4 This is a new item, not in the 2003 plan. It was added at the August 5 Executive Committee meeting.

5 This is a new item, not in the 2003 plan. It was added at the August 5 Executive Committee meeting.

6 There is industry interest, but there is neither consensus to move forward at this time nor may resources be available.

On August 5, several of the WEQ EC members discussed possibly preparing a request that would add an item to the 2004 annual plan to develop a master service agreement. The request was prepared but subsequently withdrawn by the submitter due to an expected lack of resources.

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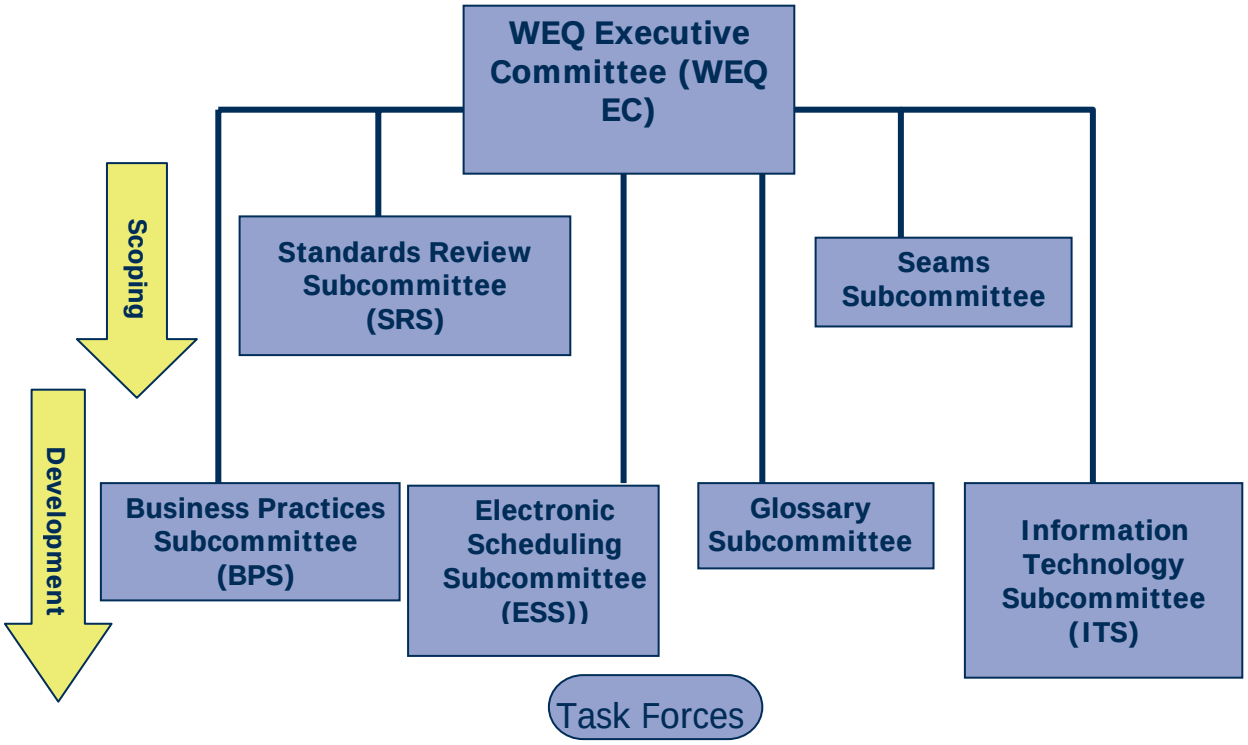
NAESB Wholesale Electric Quadrant Committee Structure



Subcommittee Leadership is:

Executive Committee: Lou Oberski (WEQ EC Chair) and Steve Cobb (WEQ EC Vice Chair)

Standards Review Subcommittee: Charles Yeung and Raj Rana
Seams Subcommittee: Steve Cobb and Joe Rossignoli
Business Practices Subcommittee: Bob Goss
Electronic Scheduling Subcommittee: Joel Dison, Andy Rodriguez and John Simonelli
Glossary Subcommittee: Tony Reed and Sherri Monteith
Information Technology Subcommittee: Monroe Landrum and Alan Johnson

TAB 8

WEQ Subcommittee Updates

I IPTF Documents

Report of the Inadvertent Interchange Payback Task Force to the WEQ Executive Committee

Task Assignment
2003 WEQ Annual Plan Item 6-IIP

Scope from Standards Request
The goal of the IIPTF is to encourage proper system control and provide equitable compensation for those who respond appropriately. The IIPTF is developing a method for settlement of Inadvertent Interchange based on data provided by NERC. It has not been determined whether the same solution will be used for both the Eastern and Western Interconnection.

Definition of Inadvertent Interchange
Inadvertent Interchange, as defined by NERC, is the difference between actual net interchange and scheduled net interchange over a given period, usually an hour. Mathematically it is the time integral of the deviation of a control area's actual net interchange from its scheduled net interchange. The IIPTF defined a Balancing Authority's Inadvertent Interchange as its Inadvertent Interchange 'with the interconnection'. (Motion F[1])

Models being considered
The following models have been considered:

- Financial settlement for all Inadvertent Interchange
- Payback in kind for all Inadvertent Interchange
- A bandwidth that would allow for a mixture of financial settlement and/or settlement in-kind.

While all three methods that have been considered, the IIPTF prefers the compromise position of bandwidth, as evidence through motion M.

Proposals for Financial Settlement Components

- Energy Price Proposals (see Native Market Pricing for Inadvertent Interchange, 04012004)

  Single Price Model

  - Highest, average or lowest energy price plus an adder .
  - Highest regional energy price plus a percentage of energy price adder with a pay-in-kind frequency bandwidth.
  - Highest energy price with a +/- 0.015 Hz no payback frequency bandwidth.
  - The price of the good contributor(s) or best price of the good contributor(s).
  - An energy price that compensates those who support frequency and provides a disincentive for those who hurt frequency.
  - A Tariff treatment

[1] Referenced motions can be found in the IIPTF Substantive and Tabled Motions document located in the appendix.

Multiple Price Model (Native Market Price)

- Each party using its own hourly market price plus a frequency dependent adder. The following issues were identified for future pricing discussion:
  - Regional versus Zonal
  - High, Low or Average
  - If regional is used should NAESB identify the regions
  - Would pricing Inadvertent Interchange energy at the producer's price or consumer's price provide appropriate market signals? (see 022004 minutes)

- Adder Proposals
  - Percentage of energy price
  - Fixed amount

The IIPTF has defined 'Frequency Bandwidth' as follows – a range of deviation around 60 Hz or the interconnection scheduled frequency. (Motion K) Any bandwidth should be determined for commercial, not reliability, purposes. (see 022004 minutes)

- Bandwidth Proposals
  - Select an arbitrary number and have the industry define the actual number through the comment period
  - Use a number that is consistent with historical deviations.
  - Setting the bandwidth based on level of megawatt deviation
  - A graduated proposal consistent with the January 2004 Lively presentation
  - A dollar value bandwidth (see 022004 minutes)

Rejected Proposals

- Frequency Control Component
- WOLF Methodology

Additional items to be considered

- Settlement process
- Arbitration and/or confidentiality
- Credit
- Over or under collection issues

Supporting Documentation
The IIPTF has created a very full record regarding each of the issues in this report. In addition to the documents listed below and attached for your reference, all other documents can be found on the NAESB web site at (http://www.naesb.org/weq/weq_iiptf.asp).

- Attachments:
  - 2003 WEQ Annual Plan Item 6-IIP Standards Request, dated March 6, 2003
  - IIPTF Substantive and Tabled Motions, dated March 8, 2004
  - Native Market Pricing for Inadvertent Interchange, dated March 25, 2004

North American Energy Standards Board

Request for Initiation of a NAESB Standard for Electronic Business Transactions
or
Enhancement of an Existing NAESB Standard for Electronic Business Transactions

Instructions:

1. Please fill out as much of the requested information as possible. It is mandatory to provide a contact name, phone number and fax number to which questions can be directed. If you have an electronic mailing address, please make that available as well.

2. Attach any information you believe is related to the request. The more complete your request is, the less time is required to review it.

3. Once completed, send your request to:

   Rae McQuade
   NAESB, Executive Director
   1100 Louisiana, Suite 3625
   Houston, TX 77002

   Phone: 713-356-0060
   Fax: 713-356-0067

   by either mail, fax, or to NAESB's email address, naesb@aol.com.

Once received, the request will be routed to the appropriate subcommittees for review.

North American Energy Standards Board

Request for Initiation of a NAESB Standard for Electronic Business Transactions
or
Enhancement of an Existing NAESB Standard for Electronic Business Transactions

Date of Request: _03/06/2003_

1. Submitting Entity & Address:

_WEQ Market Operations Subcommittee, _____
_Inadvertent Interchange Payback Task Force_____
_____
_____

2. Contact Person, Phone #, Fax #, Electronic Mailing Address:

Name : _Bob Goss (IIPTF Chair)_____
Title : _Dept. Asst. Administrator - Pwr Resources
Phone : _(706) 213-3860_____
Fax : _ _____
E-mail : _ bobg@sepa.doe.gov _____

3. Description of Proposed Standard or Enhancement:

NAESB standard for the settlement of inadvertent interchange

4. Use of Proposed Standard or Enhancement (include how the standard will be used, documentation on the description of the proposed standard, any existing documentation of the proposed standard, and required communication protocols):

The standard or standards will define the alternatives that may be used to settle Inadvertent Interchange while mitigating the potential financial gain that misuse of the current payback-in-kind methodology fails to prevent. The work of the NERC Joint Inadvertent Interchange Task Force will be used as the initial model for development and enhancement of the required standard or standards that may include energy, transmission and frequency components of Inadvertent Interchange.

5. Description of Any Tangible or Intangible Benefits to the Use of the Proposed Standard or Enhancement:

Incent good behavior of balancing actual output and scheduled output within a reliable average limit and reduce the possibility of inadvertent accumulation.

6. Estimate of Incremental Specific Costs to Implement Proposed Standard or Enhancement:

   At this point in time in the development process this task force anticipates little or no net incremental costs to implement the standard(s).

7. Description of Any Specific Legal or Other Considerations:

   As a result of developing standards on this request, NERC Policies concerning inadvertent interchange will need to be reviewed for changes.

8. If This Proposed Standard or Enhancement Is Not Tested Yet, List Trading Partners Willing to Test Standard or Enhancement (Corporations and contacts):

   None identified.

9. If This Proposed Standard or Enhancement Is In Use, Who are the Trading Partners :

   N/A

10. Attachments (such as : further detailed proposals, transaction data descriptions, information flows, implementation guides, business process descriptions, examples of ASC ANSI X12 mapped transactions):

    N/A

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via email and posting

TO: NAESB WEQ Inadvertent Interchange Payback Practice Task Force

FROM: Todd Oncken, NAESB Deputy Director

RE: IIPTF Substantive & Tabled Motions

DATE: March 8, 2004

The following is a compilation of *successful substantive* motions passed at the IIPTF since September 2003.

September 15-16, 2003

A. Mr. Cox moved, seconded by Mr. Goins, as follows: The IIPTF recognizes the discovery phase is largely complete and will begin the drafting phase. Any new discovery material must be approved by this task force through a formal motion. After limited discussion the motion passed with Mr. Illian, Mr. Blohm and Mr. Lively abstaining.

October 6, 2003

B. Moved by Mr. Terelmes and seconded by Mr. Goins. "The settlement of inadvertent as the IIPTF was tasked will be broken down into four components. 1) Inadvertent energy hourly measurement 2) Frequency hourly measurement 3) Hourly valuation for inadvertent energy 4) Valuation for contribution to frequency deviation. Valuations can be considered positive, negative or zero, and this does not preclude physical payback. The motion passed.

C. Moved by Mr. Terelmes and seconded by Mr. Illian. "The IIPTF task force recognizes that inadvertent energy and frequency deviation must be measured before it can be valued. However, the measurement of inadvertent energy and frequency deviation lies outside the scope of the IIPTF and will be a task reserved for NERC. The data received from NERC will be a sufficient measurement of inadvertent energy and frequency deviation. The motion passed.

D. Moved by Mr. Terelmes and seconded by Mr. Blohm. "NERC has agreed to provide inadvertent energy and frequency deviation measurements with hourly granularity. Although payback of inadvertent energy and contribution to frequency deviation shall be performed for each hour, reporting of such hourly information to be used for settlement purposes shall occur at such time intervals as deemed feasible by NERC. The IIPTF will accept the limitation of monthly measurement reporting frequency until such time that technology and NERC allow this data to be reported more frequently." The motion passed.

E. Moved by Mr. Terelmes and seconded by Mr. Oberski. "In an effort to arrive at a better method for the settlement of inadvertent, the IIPTF will consider only two basic methodologies. 1) Financial settlement for inadvertent 2) Physical settlement of inadvertent. The fact that inadvertent has at least two components, also allows for a combination of the above methodologies. The motion passed.

F. Moved by Mr. Blohm and seconded by Mr. Illian. "The IIPTF defines a Balancing Authority's Inadvertent Interchange as its Inadvertent Interchange 'with the interconnection.'" The motion passed.

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December 11, 2003

G. Mr. Illian moved, seconded by Mr. Reed, that "the IIPTF consider the settlement of reactive power to be out of scope with our charge and no longer be included as an issue in our discussion." Mr. Lively stated this issue should be handled consistently with the handling of inadvertent interchange. Mr. Reed agreed that at some point reactive power should be addressed but at this time the group should move forward by focusing on inadvertent interchange. Upon a procedural vote the motion passed.

H. Mr. Illian moved, seconded by Mr. Cox, "that the discussion of Time Error is consistent with the issue of Frequency." Upon a procedural vote the motion passed absent objection.

I. Mr. Illian moved, seconded by Mr. Blohm that "any methodology unable to represent negative energy prices is incompatible with a reasonable inadvertent settlement methodology, and therefore should be eliminated from discussion." Upon a procedural vote the motion passed.

J. Mr. Henry moved, seconded by Mr. Goins that "the IIPTF write a standard that may include an allowance for each interconnection to develop a method that settles inadvertent and corrects frequency error to operate in a manner to compensate for inadvertent in an interconnection's selected time intervals." Upon a procedural vote, the motion passed.

January 22-23, 2004

K. Mr. DiCaprio moved, seconded by Mr. Power, to define 'Frequency Bandwidth' as follows – a range of deviation around the interconnection scheduled frequency. Mr. Cox provided the following friendly amendment to the motion, which was adopted by Mr. DiCaprio and Mr. Power: define 'Frequency Bandwidth' as follows – a range of deviation around 60 Hz or the interconnection scheduled frequency. The amended motion passed with Mr. Henry opposed.

L. Mr. Illian moved, seconded by Mr. DiCaprio that the task force commit to having a bandwidth that requires financial settlement outside and no settlement, physical settlement or financial settlement within the bandwidth and work towards a resolution of the internal settlement. Mr. Illian and Mr. DiCaprio amended the motion to read as follows: Settlement outside a frequency bandwidth would be financial. After discussion on the motion, the motion passed with 5 in favor, 2 opposed (Mr. DiCaprio and Mr. Henry) and the rest abstaining.

February 26-27, 2004

M. Mr. Lively substituted Mr. Power's tabled motion for his motion 5, as follows: the financial settlement outside a bandwidth would be limited to inadvertent energy and not include a frequency control component. Mr. Goins seconded the motion. On Mr. Terelmes's request, the motion was amended to read as follows: The financial settlement outside a bandwidth would be limited to inadvertent energy and not include a frequency control component, except that direction of frequency could be used to indicate the good or bad nature of the Inadvertent. The motion passed on a balanced vote.

Procedural Note: This motion was made and tabled at the January 22-23, 2004 meeting.

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N. Mr. Lively moved, seconded by Mr. Oberski that the cash out of inadvertent shall be the quantity of inadvertent interchange times a pricing mechanism yet to be determined applicable to that time interval.

Procedural note: The original version of this motion was made and tabled at the December 11, 2003 meeting. The motion was revised at this meeting.

The following is a compilation of *tabled* motions passed at the IIPTF since September 2003.

November 3, 2003

A. Mr. Goins moved, seconded by Mr. Terelmes that the point at which inadvertent interchange ceases to be return-in-kind and becomes a financial settlement be no more stringent than the reliability guidelines established by NERC.

This motion was reviewed by the IIPTF on February 26-27 and it was determined to table the motion until such time that the specifics of the frequency bandwidth have been determined.

NATIVE-MARKET-PRICING FOR INADVERTENT INTERCHANGE

Prepared for

The NAESB Inadvertent Interchange Payback Task Force

by

Howard F. Illian, President
Energy Mark, Inc.
334 Satinwood Ct. N.
Buffalo Grove, Illinois 60089
March 25, 2004

1. INTRODUCTION

The NAESB Inadvertent Interchange Payback Task Force has evaluated a number of alternatives for pricing the Energy Component of Inadvertent Interchange. This paper provides support for a pricing alternative and the rational for selecting that alternative. It enumerates insights derived from preparing examples of the many pricing alternatives.

The choice of the Native-Market-Pricing[1] alternative is based as much on the disadvantages of the other alternatives as it is on the advantages of the Native-Market-Pricing alternative. One lesson that has been learned from the weaknesses and failures of power markets is that first, the pricing method must do no harm to the market. This is much the same as the primary rule of medicine. Only by following a path that first does no harm to the market is success likely to be achieved.

2. SINGLE-PRICE VERSUS MULTIPLE-PRICE MARKETS

Although I have spent literally years studying power markets, most of my efforts have been directed toward the study of Ancillary or Reliability Services. As we began to investigate the Energy Component of Inadvertent Interchange I started with many of the same biases toward single-price markets as others in the group. However, during the investigation of these alternatives I realized that there was a fundamental question with respect to the type of market within which we are working.

Single-price Design:

When restructuring began the preferred method of selecting the market price for power markets was a Single-Price auction. From a theoretical point of view, this is still the preferred method for many market designs when there are no transmission constraints that cause the market to experience multiple prices. The performance of many of these markets was observed to be less than acceptable because the transmission constraints caused price differences between market regions. These price differences could be manipulated in the Single-Price market design to extract unreasonable profits by some market participants. These market limitations contributed to the market problems experienced in California, New England, Texas and elsewhere. All of these markets have since modified their designs to include some form of Multiple-Pricing (most use Locational Marginal Pricing, LMP) to reduce the detrimental effects that valid price differences can have on the market.

[1] Defining Native-Market-Pricing: There are many different market designs currently in use in North America. Most of these designs use locational prices because locational prices enable the market to function correctly when the markets are constrained. The FERC SMD is just one of these designs that recognize transmission constraints. Markets can be constrained for many reasons including transmission constraints, losses, transmission use charges, lack of contracts or lack of contracting authority. In a constrained market, the prices for energy will vary from location to location regardless of the market design. However, the market design can affect the relative price variation. Native-Market-Pricing is the recognition of the price(s) provided by the market design used in the native area. Native-Market-Pricing explicitly recognizes there are many market designs in use and that to prevent harm to the native market, the best price to use is the price provided by that market.

Native-Market-Price Alternative:

As we began developing the energy price component, a task that was not done as part of the JIITF, I began to realize that the alternatives we were considering were based on the assumptions of a Single-Priced market. Therefore, the best of the Single-Price alternatives, the highest price plus a bad contributor adder (Example 2), still contained all of the disadvantages associated with attempting to manage a Multiple-Priced market with a Single-Price alternative. This is why I suggested that an alternative that actually used the Native-Market-Prices to represent the Energy Component be investigated along with the other alternatives. The development of the alternative examples leads me to conclude that the best alternative for pricing the Energy Component of Inadvertent Interchange is a Native-Market-Pricing alternative.

3. REVIEW OF THE ALTERNATIVES CONSIDERED

Four pricing alternatives are currently being considered by the IIPTF. They are:

1. Highest energy price plus an adder to insure that the bad contributors are penalized. (Steve Terelmes – Ameren Energy)
2. Highest regional energy price plus a percentage of energy price adder with a Pay-In-Kind frequency dead-band. (Tony Reed – Southern Company)
3. Highest energy price with a +/-0.015 Hz no payback frequency dead-band. (Al DiCaprio – PJM)
4. Each party using its own hourly market price plus a frequency dependent adder. (Howard Illian – Energy Mark)

Examples of each method are presented and discussed in Appendix 1.

The results of these examples are shown in Table 1 – Summary of Alternatives on page 5. These results are presented relative to the three components of Inadvertent Interchange as stated in the JIITF White Paper and the initial charge of the NAESB IIPTF. These three components are indicated by the column headings of E, for Energy Component, T, for Transmission Component, and F, for Frequency Component. Each of the components is evaluated with respect to the direction of the incentive, the magnitude of the incentive and the additional effect of the suggested adder on these base incentives.

4. SINGLE-PRICE ENERGY COMPONENT ALTERNATIVES

There are a number of characteristics of the single energy price alternatives that we have considered that make them unacceptable as a valuation method for Energy Component of Inadvertent Interchange. Many of these disadvantages are discussed below.

Single-Price Selection:

The selection of a Single-Price to use in a Single-Price Energy Component alternative requires the selection of the highest price from all of the available prices when frequency is low and the lowest price from all of the available prices when frequency is high. The selection of any other single price creates the opportunity for control areas to manipulate Inadvertent Interchange to their advantage, if their price is higher than the selected price when frequency is low or their price is lower than the selected price when frequency is high. This opportunity to manipulate Inadvertent Interchange is unacceptable in a market because is encourages a control area to exchange services reserved to manage reliability for economic gain thus reducing the interconnections ability to respond to emergencies and reducing reliability.

Balanced Compensation:

All of the Single-Price alternatives result in a balance between total revenue collected for Inadvertent Interchange and the total revenue paid out for Inadvertent Interchange. This revenue derives directly from the fact that Inadvertent Interchange In and Inadvertent Interchange Out is always balanced for every hour. This balancing of revenue coupled with the selection of either the highest price or the lowest

price insures that all participants with Inadvertent Interchange In will pay the same settlement price for energy and all participants with Inadvertent Interchange Out will receive the same settlement price for energy, although these prices could be negative in some cases. Therefore, the balanced compensation results in penalties in the form of price differences between the Native-Market-Price and the settlement price for those with bad Inadvertent Interchange that is more dependent on magnitude of transmission constraints than it is on the effect on reliability. This balanced compensation also results in rewards in the form of price differences between the Native-Price and the settlement price for those with good Inadvertent Interchange that is more dependent on magnitude of transmission constraints than it is on the effect on reliability. This characteristic of potential over-reward and over-penalization is unacceptable. The addition of a Bad Contributor Adder can only modify these unjustified levels of penalty and reward.

Un-penalized and Un-rewarded Participants:

In the Single-Price alternatives, the party whose price is used to set the Inadvertent Interchange price will not pay a penalty or receive a reward. In addition, others with the same price will also be in the same position of not being penalized for bad inadvertent or rewarded for good inadvertent. Therefore, to insure that these parties are properly penalized and rewarded for their behavior their price must be modified by an adder to incent the correct behavior. Even the Single-Price alternatives require a behavior adder.

Constraint Bypass:

If the market price differences result from valid system constraints, the compensation differences for Inadvertent Interchange will not maintain those price differences. This results in the provider of good Inadvertent Interchange receiving compensation that should go to the party managing the system constraint. Providing that compensation to the wrong party insures that the constraint is subject to bypass. Discouraging constraint bypass is one of the major reasons that markets are moving to Multiple-Pricing alternatives.

Conclusions:

1. Single-Price alternatives require prices from all participants to identify the highest or lowest price.
2. Single-Price alternatives result in penalties and rewards that are unrelated to the reliability problem.
3. Single-Price alternatives still require adders to insure that penalties and rewards are provided for all participants.
4. Single-Price alternatives do not respect system constraints that Native-Market-Prices represent.

5. NATIVE-MARKET-PRICE ENERGY COMPONENT ALTERNATIVES

As analysis of the pricing alternatives moved forward, I realized that the Single-Price alternative created perverse effects because of the base price differences between interconnection locations. Valid prices are required from each participant to insure that the highest or lowest price is selected. Even the choice of a Single-Price would not eliminate the need to have an adder to assure that all parties are penalized for bad Inadvertent Interchange and rewarded for good Inadvertent Interchange. Therefore, the Single-Price alternative is no simpler than a Native-Market-Price alternative. Since the Native-Market-Price alternative is no more complex than the Single-Price alternative, why not make the Energy Price Component neutral by selecting the Native-Market-Price and use just the adder to reward good behavior and penalized bad behavior.

Single-Price Disadvantages Corrected by Native-Market-Pricing:

The selection of a Native-Market-Price solution eliminates most of the disadvantages associated with the Single-Price alternatives.

1. Most opportunities to manipulate the market are eliminated because each participant sees its own price as the Energy Component Price. There is no need to select the highest or lowest price.
2. Since the prices are different, the compensation is not balanced. Therefore, there is no unjustified penalty or reward related to the price differences.
3. All participants remain unrewarded by the Energy Component Price. Therefore, the Frequency Component is the only penalty or reward for bad or good Inadvertent Interchange. This demands that the penalty reward adder, Frequency Control Component, be well supported technically. In the Single-Price alternatives the adder could be overlooked easily and based on judgment alone.
4. Since Native-Market-Prices are used there is no need to design an Energy Component pricing system. This method relies solely on the hourly market to set prices and leaves the native market in control of the Energy Component pricing rules. If the native energy market design is changed, then the change will automatically be reflected in the Inadvertent Interchange Energy Component Price. As a result, there will be no constraint bypass of valid system constraints reflected in the market prices.

Native-Market-Pricing Compensation Balance:

As with all Multiple-Pricing methods, there is no assurance that the revenues for the Inadvertent Interchange Energy Components Out will equal the revenues for Inadvertent Interchange Energy Components In. There are some factors that may allow us to estimate the long-term position that the Interconnection will be required to support.

1. If Inadvertent Interchange is driven by random error, even a Native-Market-Pricing method will tend to be revenue neutral over the long-term.
2. If as others have suggested, that higher prices tend to incent leaning on the interconnection for energy and lower prices tend to result in over-generation, it will only take a small bias in these directions coupled with the first factor to put the interconnection in a positive revenue position over the long-term.
3. This means that a method to distribute this excess revenue back to the market without creating market distortions will be required.

The above compensation balance indicates the risk associated with revenue adequacy is small.

Frequency Control Component:

The Frequency Control Component of Inadvertent Interchange would provide the penalty and reward adder. The penalties and rewards would be more than just an arbitrary adjustment. Because the Frequency Control Component is designed to provide appropriate compensation for the supply and use of Ancillary or Reliability Services provided to others to control the interconnection energy balance and interconnection frequency, it can be a cost justified tariff initially and potentially turned into a market based adjustment in the long-term as Reliability Markets develop.

6. RECOMMENDATIONS

The NAESB IIPTF should move forward with the development of a Native-Market-Price based Energy Component pricing model. Only this alternative supports all of the different market designs being implemented interconnection wide because only this model defers the full pricing mechanism to the hourly market. This method addresses both the energy and transmission congestion (constraint) components of the Inadvertent Interchange as suggested in the NERC JIITF document.

The IIPTF should investigate the compensation provided by the NERC JIITF Frequency Control Component. This could be the supplemental compensation necessary to enable native Energy Component pricing to provide the correct price signals for Inadvertent Interchange in all cases.

Summary of Alternatives

Table 1

ALTERNATIVE	EXAMPLE	1			2			3			4			5			6			7			8		
	Prices	High			High			High			High			Low			Low			Low			Low		
	Frequency	Low			Low			High			High			Low			Low			High			High		
	Inadvertent	In / Out			Out / In			In / Out			Out / In			In / Out			Out / In			In / Out			Out / In		
	Component	E	T	F	E	T	F	E	T	F	E	T	F	E	T	F	E	T	F	E	T	F	E	T	F
1. High or Low Price + Bad Contributor Adder	Incentive	G/N	B	G/N	G/N	B	G/N	G/N	B	G/N	G/N	B	G/N	G/N	B	G/N	G/N	B	G/N	G/N	B	G/N	G/N	B	G/N
	Magnitude	A/N	A	A/N	A/N	A	A/N	A/N	A	A/N	A/N	A	A/N	A/N	A	A/N	A/N	A	A/N	A/N	A	A/N	A/N	A	A/N
	Adder	Adder Not Yet Defined																							
2a. Payback-In-Kind Dead-band,	Incentive	B/G	B	B/G	B/G	B	B/G	B/G	B	B/G	B/G	B	B/G	B/G	B	B/G	B/G	B	B/G	B/G	B	B/G	B/G	B	B/G
	Magnitude	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A
	Adder	Not Applicable																							
2b. High or Low Price + % Adder	Incentive	G	B	G	G	B	G	G	B	G	G	B	G	G	B	G	G	B	G	G	B	G	G	B	G
	Magnitude	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A
	Adder	A	B	A	A	B	A	A	B	A	A	B	A	A	B	A	A	B	A	A	B	A	A	B	A
3a. No Payback Dead Band	Incentive	B	B	B	B	B	B	G	B	G	G	B	G	B	B	B	B	B	B	G	B	G	G	B	G
	Magnitude	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A
	Adder	Not Applicable																							
3b. + High Price with Frequency Reversal	Incentive	G/N	B	G/N	G/N	B	G/N	G	B	G	G	B	G	G/N	B	G/N	G/N	B	G/N	G/B	B	G/B	G/B	B	G/B
	Magnitude	A/N	A	A/N	A/N	A	A/N	A	A	A	A	A	A	A/N	A	A/N	A/N	A	A/N	A	A	A	A	A	A
	Adder	No Adder						A	A	A	A	A	A	No Adder						A	A	A	A	A	A
4. Native Market Price + Frequency Control Component	Incentive	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
	Magnitude	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
	Adder	E	N	E	E	N	E	E	N	E	E	N	E	E	N	E	E	N	E	E	N	E	E	N	E

Headings: E = Energy Component; T = Transmission Component; F = Frequency Component

A – The magnitude is arbitrary. The magnitude of the actual incentive is unrelated to the magnitude of the desired incentive.

B – Bad Incentive, discourages the correct response.

E – Equitable magnitude, magnitude of incentive is appropriate.

G – Good Incentive, encourages the correct response.

N – Neutral Incentive, neither encourages nor discourages the correct response.

1. COMMON ASSUMPTIONS USED

Each of the four pricing methods investigated are based on a common set of assumptions. The assumption(s) are:

Assumptions:

1. Each Balancing Authority has a marginal price available represented by their hourly market price.
2. These marginal prices are consistent with prices that would be observed in an active hourly interchange market.

Using only this assumption, the example methods of settling Inadvertent Interchange on an hourly basis were developed.

Example Interconnection:

For all examples, a four Balancing Authority interconnection is used. The BAs are labeled A, B, C and D.

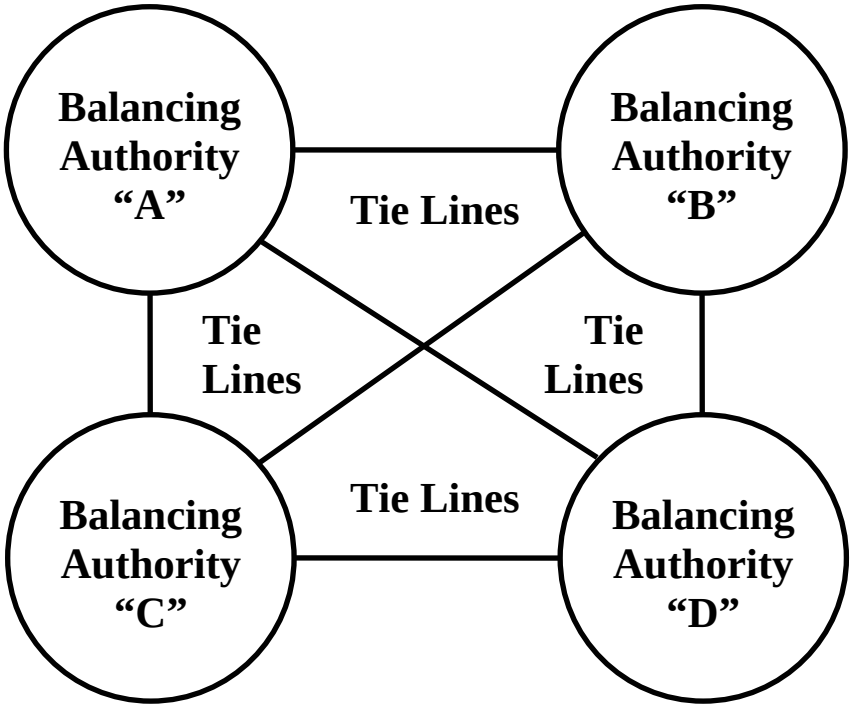

Figure 1. Example Interconnection

Example Prices

Two sets of BA prices were developed for the example. One set represents the prices that might exist during a peak period. The other set represents the prices that might exist during a minimum load period.

Peak Period Prices:

It is assumed that the marginal prices during the peak period are high and that there is a transmission constraint between A and B, with losses included in the pricing. The prices are: A = $25; B = $50; C = $35; D = $45 per MWh. These prices are consistent with transmission and loss

constraints of $25 / MWh from A to B, $10 / MWh from A to C, $20 / MWh from A to D, $10 / MWh from C to D, $5 / MWh from D to B, and $15 / MWh from C to B.

Minimum Load Prices:

It is assumed that the marginal prices during the minimum load period are low, that there are also transmission constraints, and that in some cases, the price is negative. These example prices are: A = $-5; B = $5; C = $0; D = $5 per MWh. These prices are consistent with transmission and loss constraints of $10 / MWh from A to B, $5 / MWh from A to C, $10 / MWh from A to D, $5 / MWh from C to D, $5 / MWh from C to B, and no constraint from D to B.

Transmission Congestion and Losses:

The same sets of flows and prices are used in the four examples developed. This makes it possible to calculate the costs associated with the transmission congestion and losses in the first two examples, as long as the net flows shown in this example are maintained.

Transmission Congestion and Losses for Example X-1:

The congestion cost associated with the case is a net reduction of $475.

Transmission Congestion and Losses for Example X-2:

The congestion cost associated with the case is a net increase of $475.

Transmission Congestion and Losses for Example X-3:

The congestion cost associated with the case is a net reduction of $475.

Transmission Congestion and Losses for Example X-4:

The congestion cost associated with the case is a net increase of $475.

Transmission Congestion and Losses for Example X-5:

The congestion cost associated with the case is a net reduction of $300.

Transmission Congestion and Losses for Example X-6:

The congestion cost associated with the case is a net increase of $300.

Transmission Congestion and Losses for Example X-7:

The congestion cost associated with the case is a net reduction of $300.

Transmission Congestion and Losses for Example X-8:

The congestion cost associated with the case is a net increase of $300.

2. HIGHEST PRICE PLUS BAD CONTRIBUTOR ADDER

Steve Terelmes of Ameren Energy suggested setting the settlement price at the highest price of energy plus an adder to penalize the bad contributors.

Settlement Pricing Rules:

1. If the Frequency Error for the hour is positive, the interconnection frequency is below schedule (low), use the highest hourly price of all BAs to price the settlement.
2. If the Frequency Error for the hour is negative, the interconnection frequency is above schedule (high), use the lowest hourly price of all BAs to price the settlement.
3. The price may be adjusted by an additional penalty on the bad contributor. (Note: an adder is not included in these cases)

Example 1-1:

Interconnection	Frequency Low			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	(In)	(In)	Out	Out
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	$25 / MWh	$50 / MWh	$35 / MWh	$45 / MWh
Settlement Price (Negative)	$50 / MWh	$50 / MWh	$50 / MWh	$50 / MWh
Profit or (Loss) / MWh	($25 / MWh)	$0 / MWh	$15 / MWh	$5 / MWh
Profit or (Loss) Total	($ 1,250)	$ 0	$ 600	$ 175
Interconnection Position	$ 2,500	$ 1,250	($ 2,000)	($ 1,750)

Example 1-2:

Interconnection	Frequency Low			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	Out	Out	(In)	(In)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	$25 / MWh	$50 / MWh	$35 / MWh	$45 / MWh
Settlement Price (Negative)	$50 / MWh	$50 / MWh	$50 / MWh	$50 / MWh
Profit or (Loss) / MWh	$25 / MWh	$0 / MWh	($15 / MWh)	($5 / MWh)
Profit or (Loss) Total	$ 1,250	$ 0	($ 600)	($ 175)
Interconnection Position	($ 2,500)	($ 1,250)	$ 2,000	$ 1,750

Example 1-3:

Interconnection	Frequency High			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	In	In	(Out)	(Out)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	$25 / MWh	$50 / MWh	$35 / MWh	$45 / MWh
Settlement Price (Negative)	$25 / MWh	$25 / MWh	$25 / MWh	$25 / MWh
Profit or (Loss) / MWh	$0 / MWh	$25 / MWh	($10 / MWh)	($20 / MWh)
Profit or (Loss) Total	$ 0	$ 625	($ 400)	($ 700)
Interconnection Position	$ 1,250	$ 625	($ 1,000)	($ 875)

Example 1-4:

Interconnection	Frequency High			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	(Out)	(Out)	In	In
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	$25 / MWh	$50 / MWh	$35 / MWh	$45 / MWh
Settlement Price (Negative)	$25 / MWh	$25 / MWh	$25 / MWh	$25 / MWh
Profit or (Loss) / MWh	$0 / MWh	($25 / MWh)	$10 / MWh	$20 / MWh
Profit or (Loss) Total	$ 0	($ 625)	$ 400	$ 700
Interconnection Position	($ 1,250)	($ 625)	$ 1,000	$ 875

Example 1-5:

Interconnection	Frequency Low			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	(In)	(In)	Out	Out
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	-$5 / MWh	$5 / MWh	$0 / MWh	$5 / MWh
Settlement Price (Negative)	$5 / MWh	$5 / MWh	$5 / MWh	$5 / MWh
Profit or (Loss) / MWh	($10 / MWh)	$0 / MWh	$5 / MWh	$0 / MWh
Profit or (Loss) Total	($ 500)	$ 0	$ 200	$ 0
Interconnection Position	$ 250	$ 125	($ 200)	($ 175)

Example 1-6:

Interconnection	Frequency Low			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	Out	Out	(In)	(In)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	-$5 / MWh	$5 / MWh	$0 / MWh	$5 / MWh
Settlement Price (Negative)	$5 / MWh	$5 / MWh	$5 / MWh	$5 / MWh
Profit or (Loss) / MWh	$10 / MWh	$0 / MWh	($5 / MWh)	$0 / MWh
Profit or (Loss) Total	$ 500	$ 0	($ 200)	$ 0
Interconnection Position	($ 250)	($ 125)	$ 200	$ 175

Example 1-7:

Interconnection	**Frequency High**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**In**	**In**	**(Out)**	**(Out)**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**-$5 / MWh**	**$5 / MWh**	**$0 / MWh**	**$5 / MWh**
Settlement Price (Negative)	**($5 / MWh)**	**($5 / MWh)**	**($5 / MWh)**	**($5 / MWh)**
Profit or (Loss) / MWh	**$0 / MWh**	**$5 / MWh**	**($5 / MWh)**	**($10 / MWh)**
Profit or (Loss) Total	**$ 0**	**$ 125**	**($ 200)**	**($ 350)**
Interconnection Position	**($ 250)**	**($ 125)**	**$ 200**	**$ 175**

Example 1-8:

Interconnection	**Frequency High**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(Out)**	**(Out)**	**In**	**In**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**-$5 / MWh**	**$5 / MWh**	**$0 / MWh**	**$5 / MWh**
Settlement Price (Negative)	**($5 / MWh)**	**($5 / MWh)**	**($5 / MWh)**	**($5 / MWh)**
Profit or (Loss) / MWh	**$0 / MWh**	**($10 / MWh)**	**$5 / MWh**	**$10 / MWh**
Profit or (Loss) Total	**$ 0**	**($ 250)**	**$ 200**	**$ 350**
Interconnection Position	**$250**	**$ 125**	**($ 200)**	**($ 175)**

In all of the examples 1-1 through 1-8 the Interconnection is financially neutral, but retains no funds for the settlement of transmission congestion and losses.

Conclusions:

This alternative appears to work well in many cases.

1. It removes the incentive to manipulate the system.
2. It usually rewards the good contributors and penalizes the bad contributors.

Some significant weaknesses are associated with this method.

1. The penalties and rewards are associated more with price differences than with value of energy.
2. The good contributors may not be rewarded.
3. The good contributors may not be equally rewarded.

4. The bad contributors may not be penalized.
5. The bad contributors may not be equally penalized.
6. The final compensation excludes the effects of managing transmission congestion and losses.

The only way to insure that good contributors always get rewarded and bad contributors always get penalized is to include the adder to penalize bad contributors and use those penalties to reward good contributors.

This alternative is unacceptable in this form because of the arbitrary magnitude of the penalties and rewards.

3. IN-KIND DEAD-BAND WITH HIGHEST PRICE PLUS % ADDER

Tony Reed of Southern Company suggested setting an In-Kind Dead-band with settlement outside the dead-band at the highest price of energy plus a percentage adder.

Settlement Pricing Rules:

1. Payback-In-Kind inside a frequency dead-band..
2. If the Frequency Error for the hour is negative, the interconnection frequency is below schedule (low), use the highest hourly price of all BAs plus 25% to price the settlement.
3. If the Frequency Error for the hour is positive, the interconnection frequency is above schedule (high), use the lowest hourly price of all BAs minus 25% to price the settlement.

The examples, 2a-1 through 2a-8, show the settlement for those hours when the Frequency Error is inside the dead-band.

The settlement price is determined at the time the payback is performed. The incentives are based on the price of energy at the time of payback. The interconnection position is always balanced. This is true for all examples.

Example 2a-1:

Interconnection	**Frequency Low**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(In)**	**(In)**	**Out**	**Out**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Settlement Price (Negative)	**Set at Payback**	**Set at Payback**	**Set at Payback**	**Set at Payback**
Profit or (Loss) / MWh	**Set at Payback**	**Set at Payback**	**Set at Payback**	**Set at Payback**
Profit or (Loss) Total	**Set at Payback**	**Set at Payback**	**Set at Payback**	**Set at Payback**
Interconnection Position	**$ 0**	**$ 0**	**$ 0**	**$ 0**

Example 2a-2:

Interconnection	Frequency Low			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	Out	Out	(In)	(In)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	$25 / MWh	$50 / MWh	$35 / MWh	$45 / MWh
Settlement Price (Negative)	Set at Payback	Set at Payback	Set at Payback	Set at Payback
Profit or (Loss) / MWh	Set at Payback	Set at Payback	Set at Payback	Set at Payback
Profit or (Loss) Total	Set at Payback	Set at Payback	Set at Payback	Set at Payback
Interconnection Position	$ 0	$ 0	$ 0	$ 0

Example 2a-3:

Interconnection	Frequency High			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	In	In	(Out)	(Out)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	$25 / MWh	$50 / MWh	$35 / MWh	$45 / MWh
Settlement Price (Negative)	Set at Payback	Set at Payback	Set at Payback	Set at Payback
Profit or (Loss) / MWh	Set at Payback	Set at Payback	Set at Payback	Set at Payback
Profit or (Loss) Total	Set at Payback	Set at Payback	Set at Payback	Set at Payback
Interconnection Position	$ 0	$ 0	$ 0	$ 0

Example 2a-4:

Interconnection	Frequency High			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	(Out)	(Out)	In	In
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	$25 / MWh	$50 / MWh	$35 / MWh	$45 / MWh
Settlement Price (Negative)	Set at Payback	Set at Payback	Set at Payback	Set at Payback
Profit or (Loss) / MWh	Set at Payback	Set at Payback	Set at Payback	Set at Payback
Profit or (Loss) Total	Set at Payback	Set at Payback	Set at Payback	Set at Payback
Interconnection Position	$ 0	$ 0	$ 0	$ 0

Example 2a-5:

Interconnection	Frequency Low			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	(In)	(In)	Out	Out
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	-$5 / MWh	$5 / MWh	$0 / MWh	$5 / MWh
Settlement Price (Negative)	Set at Payback	Set at Payback	Set at Payback	Set at Payback
Profit or (Loss) / MWh	Set at Payback	Set at Payback	Set at Payback	Set at Payback
Profit or (Loss) Total	Set at Payback	Set at Payback	Set at Payback	Set at Payback
Interconnection Position	$ 0	$ 0	$ 0	$ 0

Example 2a-6:

Interconnection	**Frequency Low**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**Out**	**Out**	**(In)**	**(In)**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**-$5 / MWh**	**$5 / MWh**	**$0 / MWh**	**$5 / MWh**
Settlement Price (Negative)	**Set at Payback**	**Set at Payback**	**Set at Payback**	**Set at Payback**
Profit or (Loss) / MWh	**Set at Payback**	**Set at Payback**	**Set at Payback**	**Set at Payback**
Profit or (Loss) Total	**Set at Payback**	**Set at Payback**	**Set at Payback**	**Set at Payback**
Interconnection Position	**$ 0**	**$ 0**	**$ 0**	**$ 0**

Example 2a-7:

Interconnection	**Frequency High**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**In**	**In**	**(Out)**	**(Out)**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**-$5 / MWh**	**$5 / MWh**	**$0 / MWh**	**$5 / MWh**
Settlement Price (Negative)	**Set at Payback**	**Set at Payback**	**Set at Payback**	**Set at Payback**
Profit or (Loss) / MWh	**Set at Payback**	**Set at Payback**	**Set at Payback**	**Set at Payback**
Profit or (Loss) Total	**Set at Payback**	**Set at Payback**	**Set at Payback**	**Set at Payback**
Interconnection Position	**$ 0**	**$ 0**	**$ 0**	**$ 0**

Example 2a-8:

Interconnection	**Frequency High**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(Out)**	**(Out)**	**In**	**In**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**-$5 / MWh**	**$5 / MWh**	**$0 / MWh**	**$5 / MWh**
Settlement Price (Negative)	**Set at Payback**	**Set at Payback**	**Set at Payback**	**Set at Payback**
Profit or (Loss) / MWh	**Set at Payback**	**Set at Payback**	**Set at Payback**	**Set at Payback**
Profit or (Loss) Total	**Set at Payback**	**Set at Payback**	**Set at Payback**	**Set at Payback**
Interconnection Position	**$ 0**	**$ 0**	**$ 0**	**$ 0**

The examples, 2b-1 through 2b-8, show the settlement for those hours when the Frequency Error is outside the dead-band.

Example 2b-1:

Interconnection	**Frequency Low**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(In)**	**(In)**	**Out**	**Out**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Settlement Price (Negative)	**$62.5 / MWh**	**$62.5 / MWh**	**$62.5 / MWh**	**$62.5 / MWh**
Profit or (Loss) / MWh	**($37.5 / MWh)**	**($12.5 / MWh)**	**$27.5 / MWh**	**$17.5 / MWh**
Profit or (Loss) Total	**($ 1,875)**	**($ 312.5)**	**$ 1,100**	**$ 612.5**
Interconnection Position	**$ 3,125**	**$ 1,562.5**	**($ 2,500)**	**($ 2,187.5)**

Since the frequency is low, the settlement price for the Inadvertent Interchange would be the price of the BA with the highest market sales price plus 25%.

Example 2b-2:

Interconnection	Frequency Low			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	Out	Out	(In)	(In)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	$25 / MWh	$50 / MWh	$35 / MWh	$45 / MWh
Settlement Price (Negative)	$62.5 / MWh	$62.5 / MWh	$62.5 / MWh	$62.5 / MWh
Profit or (Loss) / MWh	$37.5 / MWh	$12.5 / MWh	($27.5 / MWh)	($17.5 / MWh)
Profit or (Loss) Total	$ 1,875	$ 312.5	($ 1,100)	($ 612.5)
Interconnection Position	($ 3,125)	($ 1,562.5)	$ 2,500	$ 2,187.5

Since the frequency is low, the settlement price for the Inadvertent Interchange would be the price of the BA with the highest market sales price plus 25%.

Example 2b-3:

Interconnection	Frequency High			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	In	In	(Out)	(Out)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	$25 / MWh	$50 / MWh	$35 / MWh	$45 / MWh
Settlement Price (Negative)	$18.75 / MWh	$18.75 / MWh	$18.75 / MWh	$18.75 / MWh
Profit or (Loss) / MWh	$ 6.25 / MWh	$ 31.25 / MWh	($16.25 / MWh)	($26.25 / MWh)
Profit or (Loss) Total	$ 312.5	$ 781.25	($ 650)	($ 918.75)
Interconnection Position	$ 937.5	$ 468.75	($ 750)	($ 656.25)

Since the frequency is high, the settlement price for the Inadvertent Interchange would be the price of the BA with the lowest market sales price less 25%.

Example 2b-4:

Interconnection	**Frequency High**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(Out)**	**(Out)**	**In**	**In**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Settlement Price (Negative)	**$18.75 / MWh**	**$18.75 / MWh**	**$18.75 / MWh**	**$18.75 / MWh**
Profit or (Loss) / MWh	**($6.25 / MWh)**	**($31.25 / MWh)**	**$16.25 / MWh**	**$26.25 / MWh**
Profit or (Loss) Total	**($ 312.5)**	**($ 781.25)**	**$ 650**	**$ 918.75**
Interconnection Position	**($ 937.5)**	**($ 468.75)**	**$ 750**	**$ 656.25**

Since the frequency is high, the settlement price for the Inadvertent Interchange would be the price of the BA with the lowest market sales price less 25%.

Example 2b-5:

Interconnection	**Frequency Low**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(In)**	**(In)**	**Out**	**Out**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**-$5 / MWh**	**$5 / MWh**	**$0 / MWh**	**$5 / MWh**
Settlement Price (Negative)	**$6.25 / MWh**	**$6.25 / MWh**	**$6.25 / MWh**	**$6.25 / MWh**
Profit or (Loss) / MWh	**($11.25 / MWh)**	**($1.25 / MWh)**	**$6.25 / MWh**	**$1.25 / MWh**
Profit or (Loss) Total	**($ 562.5)**	**($ 31.25)**	**$ 250**	**$ 43.75**
Interconnection Position	**$ 312.5**	**$ 156.25**	**($ 250)**	**($ 218.75)**

Since the frequency is low, the settlement price for the Inadvertent Interchange would be the price of the BA with the highest market sales price plus 25%.

Example 2b-6:

Interconnection	Frequency Low			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	Out	Out	(In)	(In)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	-$5 / MWh	$5 / MWh	$0 / MWh	$5 / MWh
Settlement Price (Negative)	$6.25 / MWh	$6.25 / MWh	$6.25 / MWh	$6.25 / MWh
Profit or (Loss) / MWh	$11.25 / MWh	$1.25 / MWh	($6.25 / MWh)	($1.25 / MWh)
Profit or (Loss) Total	$ 562.5	$ 31.25	($ 250)	($ 43.75)
Interconnection Position	($ 312.5)	($ 156.25)	$ 250	$ 218.75

Since the frequency is low, the settlement price for the Inadvertent Interchange would be the price of the BA with the highest market sales price plus 25%.

Example 2b-7:

Interconnection	Frequency High			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	In	In	(Out)	(Out)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	-$5 / MWh	$5 / MWh	$0 / MWh	$5 / MWh
Settlement Price (Negative)	($6.25 / MWh)	($6.25 / MWh)	($6.25 / MWh)	($6.25 / MWh)
Profit or (Loss) / MWh	$1.25 / MWh	$11.25 / MWh	($6.25 / MWh)	($11.25 / MWh)
Profit or (Loss) Total	$ 62.5	$ 281.25	($ 250)	($ 393.75)
Interconnection Position	($ 312.5)	($ 156.25)	$ 250	$ 218.75

Since the frequency is high, the settlement price for the Inadvertent Interchange would be the price of the BA with the lowest market sales price less 25%.

Example 2b-8:

Interconnection	**Frequency High**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(Out)**	**(Out)**	**In**	**In**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**-$5 / MWh**	**$5 / MWh**	**$0 / MWh**	**$5 / MWh**
Settlement Price (Negative)	**($6.25 / MWh)**	**($6.25 / MWh)**	**($6.25 / MWh)**	**($6.25 / MWh)**
Profit or (Loss) / MWh	**($1.25 / MWh)**	**($11.25 / MWh)**	**$6.25 / MWh**	**$11.25 / MWh**
Profit or (Loss) Total	**($ 62.5)**	**($ 281.25)**	**$ 250**	**$ 393.75**
Interconnection Position	**$ 312.5**	**$ 156.25**	**($ 250)**	**($ 218.75)**

Since the frequency is high, the settlement price for the Inadvertent Interchange would be the price of the BA with the lowest market sales price less 25%.

In all of the above examples 2b-1 through 2b-8, the Interconnection is neutral, and retains no funds for the settlement of transmission congestion and losses.

Conclusions:

This alternative fails to mitigate the disadvantages of the current payback-in-kind method inside the frequency dead-band.

This alternative appears to work well outside the dead-band.

1. It removes the incentive to manipulate the system.
2. It always rewards the good contributors and penalizes the bad contributors.

Some significant weaknesses are associated with this method.

1. The penalties and rewards are associated more with energy price differences than with value of energy or reliability.
2. The good contributors may not be equally rewarded.
3. The bad contributors may not be equally penalized.
4. The final compensation excludes the effects of managing transmission congestion and losses.

The only way to insure that good contributors always get rewarded and bad contributors always get penalized is to include the adder to penalize bad contributors and use those penalties to reward good contributors. This alternative is unacceptable in this form because of the arbitrary magnitude of the penalties and rewards associated with both the energy and the adder.

This alternative is unacceptable in this form, but it does demonstrate the value that an adder can contribute to the solution of the problem.

4. NON-PAYBACK DEAD-BAND WITH HIGHEST PRICE PLUS FREQUENCY REVERSAL

Al DiCaprio of PJM suggested setting the settlement price at the highest price of energy with a +/- 0.015 Hz dead-band.

Settlement Pricing Rules:

1. Only hours with Frequency Error above +0.015 Hz or below -0.015 Hz will be financially settled. Hours within this frequency range will not be settled either financially or with payback-in-kind.
2. If the Frequency Error for the hour is negative, the interconnection frequency is below schedule (low), use the highest hourly price of all BAs to price the settlement.
3. If the Frequency Error for the hour is positive, the interconnection frequency is above schedule (high), use the highest hourly price of all BAs with the sign reversed to price the settlement.

The examples show the settlement for those hours when the Frequency Error is outside the dead-band.

Example 3b-1:

Interconnection	**Frequency Low**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(In)**	**(In)**	**Out**	**Out**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Settlement Price (Negative)	**$50 / MWh**	**$50 / MWh**	**$50 / MWh**	**$50 / MWh**
Profit or (Loss) / MWh	**($25 / MWh)**	**$0 / MWh**	**$15 / MWh**	**$5 / MWh**
Profit or (Loss) Total	**($ 1,250)**	**$ 0**	**$ 600**	**$ 175**
Interconnection Position	**$ 2,500**	**$ 1,250**	**($ 2,000)**	**($ 1,750)**

Since the frequency is low, the settlement price for the Inadvertent Interchange would be the price of the BA with the highest market sales price.

Example 3b-2:

Interconnection	**Frequency Low**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**Out**	**Out**	**(In)**	**(In)**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Settlement Price (Negative)	**$50 / MWh**	**$50 / MWh**	**$50 / MWh**	**$50 / MWh**
Profit or (Loss) / MWh	**$25 / MWh**	**$0 / MWh**	**($15 / MWh)**	**($5 / MWh)**
Profit or (Loss) Total	**$ 1,250**	**$ 0**	**($ 600)**	**($ 175)**
Interconnection Position	**($ 2,500)**	**($ 1,250)**	**$ 2,000**	**$ 1,750**

Since the frequency is low, the settlement price for the Inadvertent Interchange would be the price of the BA with the highest market sales price.

Example 3b-3:

Interconnection	**Frequency High**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**In**	**In**	**(Out)**	**(Out)**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Settlement Price (Negative)	**($50 / MWh)**	**($50 / MWh)**	**($50 / MWh)**	**($50 / MWh)**
Profit or (Loss) / MWh	**$75 / MWh**	**$100 / MWh**	**($85 / MWh)**	**($95 / MWh)**
Profit or (Loss) Total	**$ 3,750**	**$ 2,500**	**($ 3,400)**	**($ 3,325)**
Interconnection Position	**($ 2,500)**	**($ 1,250)**	**$ 2,000**	**$ 1,750**

Since the frequency is high, the settlement price for the Inadvertent Interchange would be the price of the BA with the highest market sales price with the sign reversed.

Example 3b-4:

Interconnection	Frequency High			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	(Out)	(Out)	In	In
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	$25 / MWh	$50 / MWh	$35 / MWh	$45 / MWh
Settlement Price (Negative)	($50 / MWh)	($50 / MWh)	($50 / MWh)	($50 / MWh)
Profit or (Loss) / MWh	($75 / MWh)	($100 / MWh)	$85 / MWh	$95 / MWh
Profit or (Loss) Total	($ 3,750)	($ 2,500)	$ 3,400	$ 3,325
Interconnection Position	$ 2,500	$ 1,250	($ 2,000)	($ 1,750)

Since the frequency is high, the settlement price for the Inadvertent Interchange would be the price of the BA with the highest market sales price with the sign reversed.

Example 3b-5:

Interconnection	Frequency Low			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	(In)	(In)	Out	Out
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	-$5 / MWh	$5 / MWh	$0 / MWh	$5 / MWh
Settlement Price (Negative)	$5 / MWh	$5 / MWh	$5 / MWh	$5 / MWh
Profit or (Loss) / MWh	($10 / MWh)	$0 / MWh	$5 / MWh	$0 / MWh
Profit or (Loss) Total	($ 500)	$ 0	$ 200	$ 0
Interconnection Position	$ 250	$ 125	($ 200)	($ 175)

Since the frequency is low, the settlement price for the Inadvertent Interchange would be the price of the BA with the highest market purchase price.

Example 3b-6:

Interconnection	Frequency Low			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	Out	Out	(In)	(In)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	-$5 / MWh	$5 / MWh	$0 / MWh	$5 / MWh
Settlement Price (Negative)	$5 / MWh	$5 / MWh	$5 / MWh	$5 / MWh
Profit or (Loss) / MWh	$10 / MWh	$0 / MWh	($5 / MWh)	$0 / MWh
Profit or (Loss) Total	$ 500	$ 0	($ 200)	$ 0
Interconnection Position	($ 250)	($ 125)	$ 200	$ 175

Since the frequency is low, the settlement price for the Inadvertent Interchange would be the price of the BA with the highest market purchase price.

Example 3b-7:

Interconnection	Frequency High			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	In	In	(Out)	(Out)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	-$5 / MWh	$5 / MWh	$0 / MWh	$5 / MWh
Settlement Price (Negative)	($5 / MWh)	($5 / MWh)	($5 / MWh)	($5 / MWh)
Profit or (Loss) / MWh	$0 / MWh	$10 / MWh	($5 / MWh)	($10 / MWh)
Profit or (Loss) Total	$ 0	$ 250	($ 200)	($ 350)
Interconnection Position	($ 250)	($ 125)	$ 200	$ 175

Since the frequency is high, the settlement price for the Inadvertent Interchange would be the price of the BA with the highest market sales price with the sign reversed.

Example 3b-8:

Interconnection	Frequency High			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(Out)**	**(Out)**	**In**	**In**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**-$5 / MWh**	**$5 / MWh**	**$0 / MWh**	**$5 / MWh**
Settlement Price (Negative)	**($5 / MWh)**	**($5 / MWh)**	**($5 / MWh)**	**($5 / MWh)**
Profit or (Loss) / MWh	**$0 / MWh**	**($10 / MWh)**	**$5 / MWh**	**$10 / MWh**
Profit or (Loss) Total	**$ 0**	**($ 250)**	**$ 200**	**$ 350**
Interconnection Position	**$250**	**$ 125**	**($ 200)**	**($ 175)**

Since the frequency is high, the settlement price for the Inadvertent Interchange would be the price of the BA with the highest market sales price with the sign reversed.

In all of the above examples 3-1 through 3-8, the Interconnection is neutral, and retains no funds for the settlement of transmission congestion and losses.

Conclusions:

This alternative appears to work well in those cases where the frequency is high.

1. It removes the incentive to manipulate the system.
2. It usually rewards the good contributors and penalizes the bad contributors.

Some significant weaknesses are associated with this method.

1. The penalties and rewards are associated more with price differences than with value of energy.
2. Good contributors may not be rewarded.
3. The good contributors may not be equally rewarded.
4. The bad contributors may not be penalized.
5. The bad contributors may not be equally penalized.
6. The magnitude of the penalties and rewards is many times greater when there is high frequency than when there is low frequency.
7. The costs of managing transmission congestion and losses are not compensated.

The unequal magnitude of the penalties and rewards for high frequency versus low frequency creates an additional problem with this method. Because the penalties and rewards for high frequency are significantly greater than the penalties and rewards for low frequency, the settlement will create a natural bias to under-generate. That bias will increase as market prices increase. Since market prices are highest during the day, the method will create the greatest bias to under-generate during the day. This is contrary to good operating practice and good reliability.

The only way to insure that good contributors always get rewarded and bad contributors always get penalized is to include the adder to penalize bad contributors and use those penalties to reward good contributors.

This alternative is unacceptable in this form and should be ranked below most of the alternatives already investigated.

5. NATIVE-MARKET-PRICE

Howard Illian of Energy Mark suggested setting the settlement price at the Native-Market-Price of each BA.

Settlement Pricing Rules:

1. Each BA would use its own Native-Market-Price for settling the Energy Component of Inadvertent Interchange.

For all examples 4-1 through 4-8, each BA would use their hourly market price to settle the Inadvertent Interchange.

Example 4-1:

Interconnection	**Frequency Low**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(In)**	**(In)**	**Out**	**Out**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Settlement Price (Negative)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Profit or (Loss) / MWh	**$0 / MWh**	**$0 / MWh**	**$0 / MWh**	**$0 / MWh**
Profit or (Loss) Total	**$ 0**	**$ 0**	**$ 0**	**$ 0**
Interconnection Position	**$ 1,250**	**$ 1,250**	**($ 1,400)**	**($ 1,575)**

The Net Interconnection Position is minus $475 and equals the decrease in cost of transmission congestion and losses.

Example 4-2:

Interconnection	**Frequency Low**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**Out**	**Out**	**(In)**	**(In)**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Settlement Price (Negative)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Profit or (Loss) / MWh	**$0 / MWh**	**$0 / MWh**	**$0 / MWh**	**$0 / MWh**
Profit or (Loss) Total	**$ 0**	**$ 0**	**$ 0**	**$ 0**
Interconnection Position	**($ 1,250)**	**($ 1,250)**	**$ 1,400**	**$ 1,575**

The Net Interconnection Position is plus $475 and equals the increase in cost of transmission congestion and losses.

Example 4-3:

Interconnection	**Frequency High**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**In**	**In**	**(Out)**	**(Out)**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Settlement Price (Negative)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Profit or (Loss) / MWh	**$0 / MWh**	**$0 / MWh**	**$0 / MWh**	**$0 / MWh**
Profit or (Loss) Total	**$ 0**	**$ 0**	**$ 0**	**$ 0**
Interconnection Position	**$ 1,250**	**$ 1,250**	**($ 1,400)**	**($ 1,575)**

The Net Interconnection Position is minus $475 and equals the decrease in cost of transmission congestion and losses.

Example 4-4:

Interconnection	**Frequency High**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(Out)**	**(Out)**	**In**	**In**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Settlement Price (Negative)	**$25 / MWh**	**$50 / MWh**	**$35 / MWh**	**$45 / MWh**
Profit or (Loss) / MWh	**$0 / MWh**	**$0 / MWh**	**$0 / MWh**	**$0 / MWh**
Profit or (Loss) Total	**$ 0**	**$ 0**	**$ 0**	**$ 0**
Interconnection Position	**($ 1,250)**	**($ 1,250)**	**$ 1,400**	**$ 1,575**

The Net Interconnection Position is plus $475 and equals the increase in cost of transmission congestion and losses.

Example 4-5:

Interconnection	**Frequency Low**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(In)**	**(In)**	**Out**	**Out**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**-$5 / MWh**	**$5 / MWh**	**$0 / MWh**	**$5 / MWh**
Settlement Price (Negative)	**($5 / MWh)**	**$5 / MWh**	**$0 / MWh**	**$5 / MWh**
Profit or (Loss) / MWh	**$0 / MWh**	**$0 / MWh**	**$0 / MWh**	**$0 / MWh**
Profit or (Loss) Total	**$ 0**	**$ 0**	**$ 0**	**$ 0**
Interconnection Position	**($ 250)**	**$ 125**	**$ 0**	**($ 175)**

The Net Interconnection Position is minus $300 and equals the decrease in cost of transmission congestion and losses.

Example 4-6:

Interconnection	Frequency Low			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	Out	Out	(In)	(In)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	-$5 / MWh	$5 / MWh	$0 / MWh	$5 / MWh
Settlement Price (Negative)	($5 / MWh)	$5 / MWh	$0 / MWh	$5 / MWh
Profit or (Loss) / MWh	$0 / MWh	$0 / MWh	$0 / MWh	$0 / MWh
Profit or (Loss) Total	$ 0	$ 0	$ 0	$ 0
Interconnection Position	$ 250	($ 125)	$ 0	$ 175

The Net Interconnection Position is plus $300 and equals the increase in cost of transmission congestion and losses.

Example 4-7:

Interconnection	Frequency High			
Balancing Authority	A	B	C	D
Inadvertent Direction (Bad)	In	In	(Out)	(Out)
Inadvertent Amount - MW	50 MW	25 MW	40 MW	35 MW
Energy Price (Selected)	-$5 / MWh	$5 / MWh	$0 / MWh	$5 / MWh
Settlement Price (Negative)	($5 / MWh)	$5 / MWh	$0 / MWh	$5 / MWh
Profit or (Loss) / MWh	$0 / MWh	$0 / MWh	$0 / MWh	$0 / MWh
Profit or (Loss) Total	$ 0	$ 0	$ 0	$ 0
Interconnection Position	($ 250)	$ 125	$ 0	($ 175)

The Net Interconnection Position is minus $300 and equals the decrease in cost of transmission congestion and losses.

Example 4-8:

Interconnection	**Frequency High**			
Balancing Authority	**A**	**B**	**C**	**D**
Inadvertent Direction (Bad)	**(Out)**	**(Out)**	**In**	**In**
Inadvertent Amount - MW	**50 MW**	**25 MW**	**40 MW**	**35 MW**
Energy Price (Selected)	**-$5 / MWh**	**$5 / MWh**	**$0 / MWh**	**$5 / MWh**
Settlement Price (Negative)	**($5 / MWh)**	**$5 / MWh**	**$0 / MWh**	**$5 / MWh**
Profit or (Loss) / MWh	**$0 / MWh**	**$0 / MWh**	**$0 / MWh**	**$0 / MWh**
Profit or (Loss) Total	**$ 0**	**$ 0**	**$ 0**	**$ 0**
Interconnection Position	**$ 250**	**($ 125)**	**$ 0**	**$ 175**

The Net Interconnection Position is plus $300 and equals the increase in cost of transmission congestion and losses.

Conclusions:

This alternative appears to work well in many cases.

1. This method removes the incentive to manipulate the system.
2. It includes the effects of transmission congestion and losses in the final compensation.
3. There are no arbitrary rewards or penalties included in the compensation.

There are some weaknesses associated with the method.

1. The good contributors are not rewarded.
2. The bad contributors are not penalized.
3. The interconnection incurs some compensation risk due to locational price differences.

If this alternative is combined with a separate method for penalizing bad contributors and rewarding good contributors, weakness 1. and 2. above could be eliminated leaving the compensation risk due to locational price differences as the only weakness.

This alternative is unacceptable in this form. However, if the interconnection risk problem can be resolved and coupled with an acceptable method to penalize bad contributors and reward good contributors such as the Frequency Control Contribution adder, this method would be superior to the others.

6. OBSERVATIONS AND RECOMMENDATIONS

Alternatives 1 and 2 are the best alternatives of those considered that do not include a provision for Native-Market-Prices. Alternative 1 requires an additional penalty and reward adder to insure that the settlement signals the correct action.

Alternative 2 is simply Alternative 1 with a dead-band and a specific energy price percentage adder. Alternative 2 is a good example of the positive effect that a penalty and reward adder can have on settlement, but the adder is arbitrary. The adder does not vary with frequency risk and, therefore, does not differentiate between levels of imbalance.

Alternative 3 does not simplify either Alternative 1 or Alternative 2 proposals. Alternative 3 also requires an additional penalty and reward adder to insure that the settlement signals the correct action in all cases.

Alternative 4 is the best alternative of those considered because it does include provision for Native-Market-Prices. When coupled with an effective penalty and reward adder it would provide the best solution to the settlement problem.

Selection of any of the four above alternatives still requires consideration of a separate penalty and reward adder to insure that the settlement signals the correct action. The Frequency Control Component would provide the necessary signal in the settlement process.

The IIPTF should continue to investigate the compensation provided by the NERC JIITF Frequency Control Component. This could be the supplemental compensation necessary to enable Alternative 1, 2 or 4 to provide the correct price signals for Inadvertent Interchange in all cases.

Electronic Scheduling Subcommittee and Information Technology Subcommittee Reports

OASIS 2 Documents

OASIS II
Scope
Version 1

April 15, 2004

North American Energy Standards Board
Electronic Scheduling Subcommittee
OASIS II Scoping Task Force

Revision History

DATE	VERSION	COMMENTS	EDITOR
04-15-2004	1.0	Initial document	Andrew Rodriquez

OASIS II Scope

In order to properly understand the breadth of OASIS II and how it may be approached, it is necessary to define the scope of OASIS II. The NAESB OASIS II Scoping Task Force has prepared the following document in order to facilitate this definition.

Relation to Overall OASIS II Project

This document, the OASIS II Scope, is intended to be one of two initial documents that are to be created by NAESB as development of OASIS II begins. Its companion, the OASIS II Vision, will describe the general end state and various stages of this project that are expected to be achieved.

Upon completion, these two documents will serve as the starting point and guideline for developing the following documents for the OASIS II Project:

- The OASIS II Use Cases, which will describe all in-scope business processes, business objects, and their associated logic.
- The OASIS II Requirements, which will support the Use Cases by detailing specific requirements and metrics
- The OASIS II Structural Design, which will describe the technical architecture and how functionality will be staged for deployment
- The OASIS II Implementation Plan, which will indicate the order and timeline of how the stages will be specified, developed, and deployed
- The OASIS II Standards and Communications Protocols, which will describe the data exchanges between the various OASIS systems and their associated business logic, and
- The OASIS II Business Practices Standards, which will indicate North-American standards to be considered when utilizing the OASIS Phase II system.

The above documents represent the deliverables expected of the OASIS II design effort. Upon completion of this work, the Standards and Communications Protocols and Business Practices will be recommended for adoption as NAESB standards.

Overall Technical Approach

In general, there will be a fundamental shift in paradigm between the OASIS systems in use today and the OASIS II systems of the future. While today's OASIS nodes are web servers operated by one or more tariff administrators, the Task Force envisions OASIS II to be a much more expansive network, comprised of many systems each performing specific tasks in the wholesale power industry. Similar to the NERC E-Tag system, which is made up of four different types of systems (services) that all work together, the

Task Force expects OASIS II will similarly be a large collection of systems exchanging information to facilitate commerce and trade, as well as support the physical operation of the bulk power system. As such, the term OASIS II is specifically meant to refer to a set of common, standardized business functionality and associated supporting electronic communication interfaces implemented between cooperating entities (e.g., market participants, market operators, etc.), and is not meant to correspond to any one or group of specific systems that implement that interface. The primary scope of OASIS II is to define the functionality of these systems and the communications standards to exchange data among these systems and the users of these systems.

In order to ensure that all stakeholders that may be impacted by OASIS II are properly considered, the OASIS II design process will incorporate formal communications plans and relationships as necessary with other industry groups representing their stakeholder interests. This includes, but is not necessarily limited to, the ISO/RTO Council and various impacted committees and subcommittees within NERC.

The focus of OASIS II will actually be on the exchange of data, rather than the usage of data. This will ensure that the solutions the Task Force proposes are applicable to various forms of market design. While there will undoubtedly be some business logic associated with the OASIS II Processes themselves, the intent is to avoid mandating specific processes whenever possible.

Scope of OASIS II Project

The scope of OASIS II can be considered to be any function where business entities exchange data related to the commerce surrounding the use of the bulk power system. This includes:

1. The interaction between market participants and various power markets, including both existing 888-style Transmission and Ancillary Service markets as well as more centralized transmission and energy markets.
2. The submission of Market data to the Interchange Authority (IA) as described within the NERC functional model; in other words, the manner in which the IA receives “transactions.”
3. The exchange of Operational data as described within the NERC functional model; in other words, communications involving the Balancing Authority (BA), Reliability Authority (RA), Transmission Service Providers (TSP), and IA. The scope of OASIS II would not include the development of any reliability policies or standards directly, but would include supporting the reliability goals established by NERC (or other reliability organizations) to the extent possible.
4. The data exchanged between marketers when writing a transaction; in other words, the process through which marketers build “source to sink” transactions and request their implementation (i.e. “scheduling”). This means defining

standards that could be used to exchange information between the parties involved in the transaction.

5. The process through which both market and operation entities exchange reliability information, such as outages, system topology, and other significant data.
6. The coordination of the implementation of Industry cyber-security standards with regard to securing these systems.
7. The provision of a mechanism through which the confidentiality of any data is preserved.
8. The exchange of settlements and billing data. This is not considered a high priority, but rather a strategic direction and goal for later development.

The standards should be flexible or comprehensive enough to accommodate regional diversity to the extent possible. OASIS II must be market-design neutral. Unless certain discrepancies between market designs are purely unworkable, no specific guidance should be offered. Instead, the systems should be designed to support as many options as possible, and leave standardization to either voluntary actions or regulatory directive.

OASIS II will provide a single standardized communication process satisfying the market interface needs of the bulk power industry.

NAESB Wholesale Electric Quadrant
Electronic Scheduling Subcommittee
OASIS II Scoping Task Force

OASIS II Vision

Version 1
Draft
April 22, 2004

OASIS II Vision

OASIS II is envisioned to provide electronic communication standards to facilitate the procurement and scheduling of energy and related services among market participants and operating entities. OASIS II should provide a seamless method for procuring and scheduling of transmission, ancillary services, and energy, regardless of region or operating entity using the standardized electronic communications. OASIS II will also facilitate standard communications between operating entities to assist in coordinating market operations (Market Redispatch, Line Loading Relief, etc.) and the exchange of operational reliability information. OASIS II will be implemented through the development of Industry Standards addressing both the technical Standards and Communications Protocols and the procedural Business Practice Standards required to achieve this vision. OASIS II will encompass but may not be limited by the implementation of the NERC Functional Model, corresponding NERC Standards and corresponding NAESB Standards.

Realizing that there is diversity in market operations and regional practices, and that not all features would apply to every market and/or region, the following are the key objectives of the vision for OASIS II.

- Facilitate Procurement of Energy and Ancillary Services
- Facilitate Procurement of both Physical and Financial Transmission Rights
- Facilitate Electronic Scheduling of Interchange Transactions
- Accommodate Financial Only Contracts
- Accommodate Regional Diversity
- Ensure Reliable System Operations
- Accommodate Market Operations for Centralized Markets
- Accommodate Data Publishing to Industry
- Support Market Monitoring
- Provide Standards for Electronic Data Communication
- Function Consistently and Reliably
- Implement in a Cost-Effective Manner

Facilitate Procurement of Energy and Ancillary Services

OASIS II will provide standardized mechanisms for the procurement of energy and ancillary services to both centralized market structures (e.g. typical ISO/RTO two-settlement markets) and non-centralized market structures (e.g. power exchanges, automated bilateral matching systems, etc). In a centralized market, this procurement will likely be achieved through the submittal of price-sensitive or price-taking energy offers and bids into the Day Ahead and Real Time markets. The energy products in a centralized market may include both energy and certain ancillary services (e.g. operating reserves and regulation). In a non-centralized market structure the required procurement of Transmission Services either separately or in coordination with Energy and/or Ancillary service procurement will need to be addressed..

Facilitate Procurement of Both Physical and Financial Transmission Rights

OASIS II will accommodate the procurement of both financial and physical transmission rights and facilitating secondary markets for trading those rights. There will also be a mechanism for tracking transmission rights that have been obtained outside of OASIS II.

Facilitate Electronic Scheduling of Interchange Transactions

OASIS II will facilitate the scheduling of energy against transmission and energy rights to occur in a timely manner. OASIS II will also facilitate tracking of both energy and transmission rights. The facilitation needed between the procurement of transmission, energy and ancillary services may vary between centralized and non-centralized markets. OASIS II will also consider the need for coordination between all parties within and between regions for these transactions, as required by the NERC functional model and NAESB Coordinated Interchange Business Practices Standard. All OASIS II systems will support real-time status updates regarding current schedules/transactions, as well as historical audit and analysis of past transactions.

Accommodate Financial Only Contracts

OASIS II will accommodate the submittal of bilateral (i.e financial only) contracts. These contracts may be for energy or ancillary commitments but do not impact the real-time operation of the bulk power system. OASIS II will provide participants a means to electronically submit these contracts for market settlement processes.

Accommodate Regional Diversity

OASIS II should implement common business models when appropriate, but allow for both regional and market diversity and innovation. Various time frames, congestion management schemes, ramping rules, ancillary services, and uses of resources must be allowed. OASIS II should also support various market models for the trading of transmission and energy, but in a manner that allows for exchange of common data to eliminate input redundancy. This means that same data field such as capacity may mean contract path capacity in a contract path model but may mean bid capacity in a financial model.

Ensure Reliable System Operations

OASIS II will support submittal of outage and load forecast data by participants. While objectives of OASIS II are the submittal of information by the participants to reliability entities, additional communications may be defined to support data exchange between reliability entities. OASIS II will ensure data is collected to support timely reliability analysis and operational management of the electric grid. As such, the data needs of reliability entities as defined in the NERC Functional Model will be considered in OASIS II.

Accommodate Market Operations for Centralized Markets

OASIS II will provide adequate information to support a variety of market operations for centralized markets. While the actual market operation functions are not part of the OASIS II scope, OASIS II must include provisions for automated data exchange to allow the market operation to perform functions such as analyze offers and bids, clear the markets and calculate LMP or other market calculations.

Accommodate Data Publishing to Industry

OASIS II will provide adequate information to support a variety of market analysis by participants. This includes provision of automated data exchange to analyze market conditions, review current operation statuses (i.e. ATC, outages), informal and/or formal bulletin boards to match buyers and suppliers etc.

Support Market Monitoring

OASIS II will provide the capability for access to and viewing of data by market monitors. Market Monitors may also require access to data that will not be provided by OASIS II, such as proprietary transaction information, or may require immediate access to data that may not immediately be available on OASIS II.

Provide Standards for Electronic Data Communication

OASIS II systems will be developed with consistent electronic interfaces (e.g., common nomenclatures, common data models, etc…). The consistent electronic interfaces will facilitate a market participant's ability to implement transactions through a single portal. OASIS II will also define user interface standards such as common navigational paradigms for each user class (e.g. marketer, transmission provider, etc…).

Function Consistently and Reliably

OASIS II systems will be reliable. Hardware and software systems should exist to ensure that the OASIS II system is consistently available. Systems will be compliant with Industry Standards, tested, and correctly implemented prior to being allowed to participate as an OASIS II system. Systems will also provide for secure communications to ensure both the integrity of data exchange and protection of confidentiality of all information. OASIS II systems will also meet performance requirements for the exchange of data and completion of all related processes.

Implement in a Cost-Effective Manner

Finally, implementation of OASIS II systems will be managed in a cost effective manner. Technical standards will be developed in light of current industry trends and widely

available software tools that will reduce the cost of implementation. The architecture willt be both hardware and software platform independent. Selection of technologies that have already achieved a wide degree of standardization and adoption through other standards bodies (e.g., W3C, OASIS, ebXML etc.) should be evaluated for applicability to OASIS II. To promote a cost effective transition from existing system implementations (e.g., OASIS 1A, e-Tagging, etc.), the leveraging of concepts and components from these existing systems should be evaluated wherever practical.

SRS Documents

Scope Document
For
NERC Operate Within Interconnection Reliability Operating Limits (IROLs)

NAESB Standard Request # R30317 In Coordination With Input from the NERC Market Committee

The North American Electric Reliability Council has sought to establish an industry reliability standard for establishing requirements for the operation of the interconnected bulk power system within specified operating limits to avoid uncontrolled cascading outages over a wider area that could threaten the reliability of the bulk transmission network. NAESB's Standards Review Subcommittee seeks to establish companion standard business practices to complement the reliability requirements to be set forth by NERC.

NERC Proposed Standard(s) and date:
200 – Operate Within Interconnection Reliability Operating Limits, July 1, 2003
201 - Interconnection Reliability Operating Limit Identification, July 1, 2003
202 – Monitoring, July 1, 2003
203 – Analyses and Assessments, July 1, 2003
204 –Actions, July 1, 2003
205 – Data Specification & Collection, July 1, 2003
206 – Data Provision, July 1, 2003
207 – Action Plan, July 1, 2003
208 – Reliability Authority Directives, July 1, 2003

Description and Background

The proposed NERC Reliability standard seeks to prevent instability, uncontrolled Separation, or cascading outages that adversely impact the reliability of the bulk transmission system.

This NERC standard will address the following areas:
- Identification of interconnection reliability limits.
- Monitoring of the system for interconnection reliability limits.
- Analyze and assess system conditions based on monitored interconnection reliability limits.
- Specify data and collection needed for monitoring interconnection reliability limits.
- Action plan utilized by Reliability Authorities to maintain operations within interconnection reliability limits.
- Requirements apply to entities performing various electric system functions, as defined in the NERC Functional Model.

The NERC proposed standard raises the following possible business practice concerns and questions to the NAESB Executive Committee:

> NERC requires that the RCs of the bulk transmission system have in place procedures to effectively manage transactions in the event of overload on the system. These procedures may impact tariff service priorities and affect commercial market transactions that transpire both within and between markets.
>
> Developing business practices for curtailment processes may entail that all transactions are tagged or follows the processes developed by NAESB's Electronic Scheduling Subcommittee.
>
> There are questions on whether the development will be focused on national standard, a standard encompassing regional differences, or if the standard will be primarily a communication standard to be applicable on a national basis.
>
> Regarding the list of facilities subject to the interconnection reliability operational limits, will this list be the only set of facilities employed by both NERC for reliability requirements as well as a NAESB Business Practice Standard?

The NAESB SRS and NERC MC realize the need for additional companion business practice standards beyond those currently in place surrounding control of operating limits. However, the level to which the standard should be applied remains unclear.

Reliability standards are currently in place to ensure control area operators observe reliability limits, and for the most part these limits are observed. The problem is that in order to stay within prescribed limits, control areas may be obligated to relieve congestion in their own area utilizing a set of procedures that maycause overloads in neighboring areas. Other problems arise when a control area operator has a transmission constraint on an element at the control area's border. In these instances, that control area's congestion relief procedure may employ a business or market process that meets the obligations of the reliability standards for its own control area, but may negatively impact the business or market process of the neighboring control area. These types of overloads are very difficult to control with only generation inside the control area and are best managed either by standardization of a congestion relief process or coordination of congestion relief processes of the affected control areas. Thus, the working group concludes that additional business standards are needed to avoid shifting problems from one control area to another, and to ensure effective control of constraints at the borders between control areas.

Today, in the Eastern Interconnection, the primary method for interconnected congestion management is the NERC Transmission Loading Relief TLR) process. When a control area operator needs relief on a transmission element, a TLR request is issued and transactions currently flowing in the direction of the constraint are curtailed. In some areas, most notably in areas utilizing a market driven congestion relief mechanism, TLRs are used only after all internal redispatch options have been exhausted. Others use TLRs as the first step in controlling overloaded elements. There are also plans between RTOs utilizing market relief mechanisms to redispatch resources down to appropriate levels to

ensure one RTO is not over utilizing the transmission system in a neighboring control area and thus causing the congestion. In the Western Interconnection, the primary means of operating within interconnected reliability limits involves using previously identified "qualified paths".

Because of the already existing differences between the interconnections, as described above, a single nationwide business standard for congestion management may not bepossible. On the other hand, a multitude of business standards to provide congestion relief, for transmission systems that operate in an interconnected fashion, may not lend well to facilitating transactions between markets (i.e.-Seams Issues). Further discussion and investigation are needed to determine if multiple operating philosophies are acceptable for purposes of accommodating market transactions, particularly for those transactions that cross market and Reliability Authority borders.

Regardless of the breadth of geographical coverage, the standard should address the following areas:

- Identification of interconnection reliability operating limits. Control areas / RTOs should post and maintain a list of interconnected reliability limits they operate to, so that other control areas / RTOs can maintain a copy of the list in their own systems and ensure they are prepared to adjust unit output for the limit.
- Monitoring of the system for interconnection reliability operating limits. All control areas / RTOs should be responsible for monitoring the list of interconnected reliability limits mentioned above.
- Analyze and assess system conditions based on monitored interconnection reliability limits, to determine when action needs to be taken to alter flow patterns and increase the margin on elements that are approaching their limit.
- Data collection specification. As a guide for an appropriate level of monitoring, the standard should specify data collection needed for monitoring interconnection reliability limits.
- Action plan utilized by operators to maintain operations within interconnection reliability limits. The standard should contain a checklist and procedure for operators to follow in order to implement control on interconnected reliability limits.

The standard should build off of the existing processes and procedures used in each interconnection to the extent practical. The standard should realize differences in current methods of transaction management due to market based versus non-market based areas, and cover interactions of each of these types of areas.

- Practices for management of transaction curtailment including:
  - Timing
  - Priority
  - Magnitude
  - Duration
  - Types of methodologies used
  - Informing parties of the reloads and the methodologies used

- Affected Parties communicating their agreement on the reloads.

- Possible Approaches for a NAESB Business Practice for Congestion Management

  - One option is to develop the proposed companion standard based on the methods included in the Joint Operating Agreement between PJM and MISO, to be implemented later this year. The sample is attached as Appendix A.

  - For areas that do not employ market mechanisms for congestion relief (FERC Pro Forma 888 Point-to-point service), a congestion market mechanism could be developed to relieve congestion. Some possible requirements:
    - Communication between RAs and market of pending constraints
    - Electronic bulletin board posting of prices to "buy-through" congestion (by operator and/or customers)
    - Operator driven market price to keep bi-lateral schedules based on real-time system conditions,
    - Bids and offers to displace higher priority bi-lateral transactions (assumes same path and same PTDFs (Congestion price would be based on bi-lateral schedule's PTDF)
    - Redispatch (with prices)

Appendix A to MSSCWG Response to MC

Operate Within Interconnection Reliability Operating Limits Standard - Sample

Description and Background:

As RTOs / ISOs expand and implement different means to control transmission congestion, one of the primary seams issues that must be resolved is how different congestion management methodologies (market-based and traditional) will interact to ensure that operating limits are still met. This document proposes an industry standard for the operation of the bulk power system and the business practices needed to operate within interconnection reliability limits.

The proposed solution will greatly enhance current IDC granularity by utilizing existing real-time applications to monitor and react to flowgates external to an operating entity's footprint. Given that operating entities today utilize different means of controlling transmission congestion, be it pricing signals, direct unit control, or transmission loading relief (TLR) requests, the proposal is broad enough to cover three possible interactions between neighboring operating entities:

- Market Based to Market Based
- Market Based to non Market Based
- Non Market Based to non Market Based

Overview:

Operating entities will continue to be ultimately responsible to ensure flows on transmission facilities within their control are below the prescribed limits, but will have improved measures to get relief from neighboring areas when needed. When an operating entity indicates that flow reduction is needed on a particular flowgate, the neighboring entities will then redispatch units in that area down to a pre-determined level. To accomplish this, the neighboring areas will monitor the contribution from their units (their "Market Flow") on the affected flowgate, and dispatch the units to reduce that contribution. To effect this coordination of congestion management activities, this proposal includes a methodology for determining both firm and non-firm flows resulting from operating entity dispatch on external parties flowgates, used to establish the pre-determined levels for areas to reduce to.

Market Flows are defined as the flows generated from an operational entity's dispatch, and is equal to the sum of firm and non-firm flows. The firm components consist of the

flows created both through serving Network Native Load (NNL) and by those schedules flowing on Firm transmission reservations (7-F). For the purposes of this proposal, both firm transmission and NNL schedules will be referred to as the **NNL** component of Market Flows, and are considered firm.

The remainders of Market Flows, therefore, are non-firm. When the values of these flows are known, they can be treated as equivalent to non-firm transmission service. As such, Reliability Coordinators can request operating entities provide relief under TLR based on these transmission priorities.

By applying the above philosophy to the problem of coordinating congestion management, we can determine not only the impacts of an operating entity's dispatch on a particular flowgate, we can also determine the appropriate firmness of those flows. This results in the ability to coordinate both proactive and reactive congestion management between operating entities in a way that respects the current TLR process, while still allowing for the flexibility of internal congestion management based on Locational Marginal Pricing or other methods of redispatch.

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

- **Coordinated Flowgate Definition.** In order to ensure that impacts of dispatch are properly recognized, a list of flowgates must be developed around which congestion management may be effected and coordination can be established. This list would include the component being monitored and the applicable limit, plus the historical firm and non-firm flows from each operating entity.
- **Congestion Management.** By coordinating congestion management efforts and enhancing the TLR process to recognize both untagged internal flows and data of finer granularity, we can ensure that when TLR is called, the appropriate non-firm flows are reduced before firm flows. This will result in a reduction of TLR 5 events, as more relief will be available in TLR 3 to mitigate a constraint.

Flow Calculations:

When an operating entity's dispatch creates flows on a Coordinated Flowgate, those flows can be quantified and considered the **Directional Market Flow.** Market flow is then further designated into two components: **NNL Flow,** which is energy flow related to contributions from the Network Native Load serving aspects of the dispatch, and **Economic Dispatch (ED) Flow,** which is energy flow related to the Market-Based Operating Entity's market operations. These distinctions are important, as the NNL Flows are considered firm, while the Economic Dispatch flows are not.

Each operating entity will calculate their actual real-time and projected Directional Market Flows, as well as their Directional NNL Flows, on each Coordinated Flowgate. These values will allow the operating entity to determine the Economic Dispatch (ED) Flows created by the markets operations, or non-market dispatch.

Congestion Management

On a periodic basis, the operating entity will calculate Directional Market Flows for all Coordinated Flowgates. These flows will represent the actual flows in each direction at the time of the calculation, and be used in concert with the previously calculated NNL Limits to determine the portion of those flows that should be considered firm and non-firm.

Every fifteen minutes, the operating entity will be responsible for providing to Reliability Coordinators the following information:

- NNL Flows for all Coordinated Flowgates in each direciton
- Economic Dispatch Flows for all Coordinated Flowgates in each direction

This information will be provided for both current hour and next hour, and is used in order to communicate to Reliability Coordinators the amount of flows to be considered as the result of firm service on the various Coordinated Flowgates in each direction. When NNL Limit forecast is calculated to be greater than Market Flow for current hour or next hour, actual NNL Limit (used in TLR5) will be set equal to Market Flow.

Additionally, every hour the Market-Based Operating Entity will submit to the Reliability Authority a set of data describing the marginal units and associated participation factors for generation within the market footprint. The level of detail of the data may vary, as different regions will have different unique situations to address. However, this data will at a minimum be supplied for imports to and exports from the market area, and will contain as much information as is determined to be necessary to ensure system reliability. This data will be used by the Reliability Authority to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

Operating entities will have the list of third party/external Coordinated Flowgates modeled as monitored facilities in its EMS. The limits an operating entity will use for these third party flowgates will be the NNL values determined by the NNL Calculations.

The Operating Entity will upload the real-time and projected flows, as well as the delta of the NNL and actual flows on these flowgates, to the IDC every 15 minutes. When the real time actual or projected flows exceed these NNL values on a flowgate and the Reliability Coordinator who has responsibility for that flowgate has declared a TLR 3a or higher, the operating entity will redispatch its system to the amount required by the IDC. The amount of redispatch will be calculated by the IDC. In a TLR 3, the Operating Entity could be required to redispatch to the full amount of economic dispatch over the NNL Limit. Note the operating entity may provide relief through either 1.) a reduction of flows on the flowgate in the direction required, or 2.) an increase of counterflows on the flowgate.

Operating Entities will implement this redispatch using the most economic solution (where applicable) while simultaneously ensuring that each of the bound constraints is

resolved reliably. Additionally the Operating Entity will make any transaction curtailments as specified by the NERC IDC.

Using this method, the relief on the constrained flowgate will be faster than the 30 minutes required by TLR schedule curtailments, because when the bounds are applied, the systems are designed to provide relief within 15 minutes. The RC calling the TLR will be able to see the relief provided on the flowgate as the operating entity continues to upload their contributions to the real-time flows on this flowgate.

Business Practices Documents

North American Energy Standards Board
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via email and posting

TO: NAESB WEQ Business Practices Subcommittee Participants

FROM: Rae McQuade, Executive Director

RE: Wholesale Electric Quadrant Business Practices Subcommittee (BPS) Meeting Announcement & Agenda – May 11, 2004

DATE: April 14, 2003

Dear WEQ BPS Interested Parties,

As was noted in the recent Executive Committee meeting and related NERC meetings, the WEQ BPS will meet to discuss the transition of the business practices in the existing NERC policies from those NERC policies to NAESB business practices. The goal of the meeting is to transfer the business practices "as is" with modifications to reflect the NERC functional model terminology. NERC is undertaking a similar effort spearheaded by Gerry Cauley and the NERC Standards Transition Management Team (STMT), and several of the standing committees have already begun identifying the reliability standards in the existing policies (the NERC Operations, Planning and Markets Committees).

Below are the specifics of the meeting:

WHERE: NAESB Offices, 1301 Fannin, Houston, Texas

WHEN: 1:00 p.m. to 5:00 p.m. Central

The meeting location information including nearby hotels and maps can be downloaded from the NAESB web site for the WEQ BPS, (http://www.naesb.org/weq/weq_bps.asp). Lunch will be served immediately prior to the meeting.

The NERC functional model and the NERC policies will be posted and provided as work papers – amended policies will be provided and posted as they are received from NERC. A draft agenda is shown following. All of our work will be coordinated with NERC to ensure that all business practices are correctly captured and reflect the existing NERC policies and functional model language.

Please call the office (713-356-0060) for call-in instructions if you would like to participate but are unable to travel to the meeting. Phil Cox of AEP will preside over the meeting. This, as with all NAESB meetings, is an open meeting, regardless of membership status in NAESB. We look forward to your attendance.

Best Regards,

Rae McQuade

Rae McQuade
Executive Director, North American Energy Standards Board

cc: Mark Fidrych
Glenn Ross
Mike Grim
Linda Campbell
Gerry Cauley
Bill Lohrman
Don Benjamin
Gordon Scott
Michael Desselle
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WHOLESALE ELECTRIC QUADRANT BUSINESS PRACTICES SUBCOMMITTEE MEETING
DRAFT AGENDA

1:00 p.m. to 5:00 p.m. Central, May 11, 2004 – Houston, Texas

1 PM C 1. Welcome
- Antitrust Guidelines
- Welcome to attendees

2. Adoption of Agenda

3. Status of NERC Efforts

4. Description of NAESB Process and Goal for Adoption of Baseline Business Practices that mirror existing NERC policies

5. Review of each NERC policy, redlines from NERC where they exist and the NERC Functional Model to begin the determination of the business practices.

6. Preparation of request for the development of business practices standards to support existing NERC policies

7. Next Steps and Assignments – including drafting of recommendations

8. Calendar of Meetings and Timeline of Activities

9. Other Business

5P C 10. Adjourn

Seams Documents

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via email and posting

TO: NAESB WEQ Seams Subcommittee Participants and Posting for Interested Parties

FROM: James Cargas, NAESB Deputy Director

RE: WEQ Seams Subcommittee Conference Call Minutes – April 19, 2004

DATE: April 23, 2004

NAESB Wholesale Electric Quadrant
Seams Subcommittee Conference Call
April 19, 2004 – 1:00 p.m. to 4:00 p.m. Central

Draft Minutes

1. Welcome

Mr. Cobb opened the meeting and the participants introduced themselves. Mr. Cargas gave the antitrust advice. The agenda was reviewed and no modifications were made. The agenda was adopted by consensus. The minutes from the January 16, 2004, conference call were reviewed and adopted by consensus.

2. Summary of Joint Interface Committee (JIC) Meeting on Feb. 18-19, 2004

Mr. Cobb summarized the action taken by the Joint Interface Committee (JIC) on the Seams Catalog at its recent meeting in New Orleans on Feb. 18-19, 2004. Of the 134 seams issues identified by the Seams Subcommittee, consensus was reached on 97 issues, with 22 of these specifically assigned to NAESB. Another 37 issues on which consensus could not be reached, without significant additional material collected and prepared, were listed as undetermined. The matrix circulated by the NAESB Office contained the 22 seams issues assigned to NAESB by the JIC plus 20 seams issues labeled by the JIC as "undetermined" or "multiple." These 20 issues will receive further review by the Seams Subcommittee during today's call.

3. Methodology Used in Grouping Seams Issues

Mr. Cobb explained the process used to group these 42 seams issues into 14 groupings that could potentially produce approximately 12 new NAESB WEQ standards.

On April 2, 2004, a request for prioritization of these issues was sent out. In response, 11 sets of comments were received from the following organizations:[1] American Transmission Co. (ATC); Bonneville Power Administration (BPA); Consumers Energy; Entergy; International Transmission Co. (ITC); ISO/RTO Council (IRC); Mirant; PSEG; Salt River Project (SRP); Tennessee Valley Administration (TVA); TXU Energy; and We Energies.

The commenters used a scale of 1 to 3 to prioritize each seams issue. After some discussion, consensus was reached that the rankings would have the following meaning:

Priority 1	High Priority (yellow)	WEQ should begin addressing in 2004
Priority 2	Medium Priority (green)	WEQ should begin addressing in 2005
Priority 3	Low Priority (blue)	WEQ should begin addressing in the future, if at all, depending on external developments

[1] Subsequent to the call, 3 comments were received bringing the total to 11.

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Using these rankings, Mr. Cobb totaled them so that a low score would generally indicate consensus among the commenters that the seams issue was a higher priority than a high scoring issue. Combining these rankings with the existing categories, 1st sub-categories, and 2nd sub-categories, Mr. Cobb found that 14 different groupings emerged. Four groupings fell into the high priority category (scoring 8-14). Three groupings fell into the medium priority category (scoring 15-18). Five groupings fell into the low priority category (scoring 18-21). There were two additional groupings of issues that the WEQ was already working on. In a matrix posted on the NAESB web site, these groupings were given the priority color codes explained above.

This approach was discussed and ratified by the group. It was understood that the larger groupings may see periphery issues drop out once drafting begins at the task force level. It was also understood that completing any standards by 4th Quarter 2004 was an unrealistic goal. It was noted that NERC's acceleration of its development of version zero reliability standards would represent a significant drain on resources. However, significant progress at the task force level could be accomplished on the higher priority seams issues with the goal of completing these standards by early to mid-2005.

4. Review of Groupings

Next, Mr. Cobb led a discussion of each Grouping.

High Priority Seams Issues

a. Group 1: Transmission Service / Transmission Market Standard Product Definitions and Priorities

Group 1 consists of Original #4, 103 and 141, and received a score of 13. By consensus this group was identified as one of the most important areas for NAESB to address. Ms. Anderson noted that two issues implicated OASIS. Mr. Bissonnette emphasized the importance of the timing element of these issues.

b. Group 2: Transaction Scheduling / Interchange Scheduling Standardized Protocols

Group 2 consists of Original #8, 12, 41, 78, 19, 104 and 106, and received a score of 14. By consensus this group was also identified as one of the most important areas for NAESB to address. Ms. Crocket and Mr. Porter emphasized the importance of seams issues #79 and 41.

c. Group 3: Market Standards / Energy Market Standards Produce Definitions

Group 3 consists of Original #3, 10, 25, 34 and 139, and received a score of 14. By consensus this group was identified as an important area for NAESB, however, not as important as addressing Groups 1 and 2. Ms. Anderson recommended moving seam issue #42 (data visibility) to Group 5 where it fit better. The group agreed with the recommendation.

d. Group 4: Congestion Management / Various Subcategories

Group 4 consists of Original #9, 35, 36 and 138, and received a score of 13. Although an important area for NAESB to address, the consensus was that NERC is already looking into these seams issues in the normal course of Policy 9's evolution in drafting their version 1.0. Mr. Brown emphasized that close coordination with NERC would be essential to resolving these seams issues. Consensus was reached that these issues would be put on hold at NAESB until a review of NERC's final efforts on Policy 9 was possible.

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Medium Priority Seams Issues

e. Group 5: Market Standards / Market Standard Communication Protocol and Transparency

Group 5 consists of Original #42, 52 and 140, and received a score of 15. Although an important issue for NAESB to address, consensus was that it should remain a medium priority issue to be addressed in 2005.

f. Group 6: Market Standards / Market Standard Operating Time

Group 6 consists of only Original #1, and received a score of 15. Ms. Crockett noted that this could lead to the defining of an "energy day." Mr. Reed and Mr. Dayney noted that GECTF may come to address this seam issue in their efforts.

g. Group 7: System Reliability / Interchange Schedule Ramping Requirements

Group 7 consists of only Original #50, and received a score of 15. After a discussion of NERC's efforts in this area, consensus was reached that NAESB should track NERC's progress, and take this issue up only if NERC decides to pass.

Low Priority Seams Issues

h. Group 8: Transmission Service / Transmission Service Procurement and Settlement

Group 8 consists of Original #6, 28, 33, 67 and 117, and received a score of 17.

i. Group 9: Planning / Transmission Expansion and Generator Interconnection Coordination

Group 9 consists of Original #26, 46, 57 and 114, and received a score of 18. After some discussion, it was noted that this seams issue will be driven more by FERC than NAESB.

j. Group 10: Market Design / Reactive Power Compensation

Group 10 consists of only Original #16, and received a score of 18. Mr. Brown and Ms. Wicks noted that this was an important issue for generators, i.e., suppliers. Mr. Dotterweich said a FERC technical conference was being planned, and that NAESB should track this issue at FERC before taking action. The group agreed that now was not the time to move forward on this issue.

k. Group 11: Market Monitoring / Compliance

Group 11 consists of only Original #11, and received a score of 19.

l. Group 12: Market Design / Green Power Market

Group 12 consists of only Original #113, and received a score of 21. Ms. Anderson related that there is significant support for such a national standard in the green power community.

Seams Issues Already Being Addressed by WEQ

m. Group 13: Market Standards / Physical and/or Financial Resolution of Inadvertent Interchange

Group 13 consists of only Original #14. It is currently being address by the Inadvertent Interchange Payback Task Force (IIPTF).

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n. Group 14: Unscheduled-Parallel Path Flow Management / Compensation for Unscheduled-Parallel Path Flow

Group 14 consists of Original #13, 15, 29, 134 and 142. It is also currently being address by the Inadvertent Interchange Payback Task Force (IIPTF).

5. Next Steps

Mr. Cobb explained the next steps for the Seam Subcommittee. First, the WEQ Executive Committee (EC) will review the results of this meeting at its May 4 meeting in Florida. Second, the Subcommittee should begin drafting requests for standards of its highest priority seams issues for submission to the Triage Committee this summer. It is assumed that the Triage Subcommittee would recommend assignment to the wholesale electric quadrant. Third, the EC at its August 24 meeting would approve such an assignment. The WEQ members of the EC would then have the choice of assigning the requests to back to this subcommittee, another existing subcommittee, or create a new subcommittee. And fourth, once the assignment to a subcommittee is made, the subcommittee would review the request and begin drafting standards. The goal is to be drafting standards for the highest priority seams issues by the end of 2004.

Three Request Drafting Teams Formed:

- Mr. Smith volunteered to head the request drafting team for Group 1 (Transmission Services).
- Ms. Crockett agreed to have someone from TVA head the request drafting team for Group 2 (Transaction Scheduling).
- Ms. Anderson and Mr. Rossignoli volunteered to head the request drafting team for Group 3 (Market Standards).

Action Items:

- Mr. Cargas will update the Matrix Summary with the additional comments from TVA, Mirant and BPA, and circulate via the Seams Subcommittee list serv.
- Mr. Cargas and Mr. Cobb will update the Priority Summary document for the EC meeting. It will be circulated to the Seams Subcommittee list serv prior to that time for comments and refinement (update attached to these minutes below).
- Mr. Cobb will solicit additional volunteers from among the original submitters for the 3 Standards Request Drafting Teams being formed.
- Mr. Smith, Ms. Crockett, Ms. Anderson and Mr. Rossignoli will start the drafting process for their respective drafting teams once the WEQ Executive Committee approves the priority rankings.

No future meeting date was set. The consensus was that the conference call meetings were effective. However, Ms. Anderson requested that a face-to-face meeting be scheduled for the Standard Request drafting teams prior to the start of the drafting effort.

6. Adjourn

The meeting adjourned at 2:40 p.m. Central.

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7. Attendance

	Name:		Organization:	NAESB Member:	Segment:
1	Brenda	Anderson	Bonneville Power Administration	Yes	Marketers
2	Paul	Berry	Indep. Elec. Market Op. (IMO)	No	
3	Victor	Bissonnette	Hydro Quebec Transenergie	Yes	Transmission
4	Ken	Brown	PSEG	Yes	Transmission
5	James	Cargas	NAESB	N/A	Staff
6	Steven	Cobb	Salt River Project	Yes	Transmission
7	Valerie	Crockett	Tennessee Valley Authority	Yes	End Users
8	Steve	Dayney	Xcel Energy	Yes	Marketers
9	Andrew	Dotterweich	Consumers Energy	Yes	Generation
10	Ken	Gates	Conectiv	Yes	Transmission
11	Barry	Green	Ontario Power Generation	Yes	Generation
12	Bill	Heinrich	New York Public Service Commn.	Yes	End Users
13	Alan	Johnson	Mirant	Yes	Marketers
14	Sandy	Murray	We Energies	Yes	Distribution
15	Marjorie	Perlman	Energy East	Yes	Transmission
16	Jansen	Pollock	Constellation New Energy	Yes	Distribution
17	John	Porter	Tennessee Valley Authority	Yes	End Users
18	Tony	Reed	Southern Company	Yes	Generation
19	Joe	Rossignoli	National Grid	Yes	Transmission
20	Jerry	Smith	Arizona Public Service Company	Yes	Transmission
21	Karl	Tammar	New York ISO	No	
22	Julie	Voetk	American Transmission Co.	Yes	Transmission
23	Tonya	Wicks	Edison Electric Institute	Yes	Not Declared

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Seams Catalog Priority Summary
Updated April 23, 2004

Priority 1 – High Priority Issues

Group 1
Category: **Transmission Service**
Sub-Category: Transmission Market Standard Product Definitions and Priorities
Average Score: 12
Orig #: 4, 103, 141

Group 2
Category: **Transaction Scheduling**
Sub-Category: Interchange Scheduling Standardized Protocols
Average Score: 14
Orig #: 8, 12, 41, 78, 79, 104, 106

Group 3
Category: **Market Standards**
Sub-Category: Energy Market Standard Product Definitions
Average Score: 14
Orig #: 3, 10, 25, 34, 139

Group 4
Category: **Congestion Management**
Sub-Category: All
Average Score: 13
Orig #: 9, 35, 36, 138

Priority 2 – Medium Priority Issues

Group 5
Category: **Market Standards**
Sub-Category: Market Standard Communication Protocols and Transparency
Average Score: 15
Orig #: 42, 52, 140

Group 6
Category: **Market Standards**
Sub-Category: Market Standard Operating Time
Average Score: 15
Orig #: 1

Group 7
Category: **System Reliability**
Sub-Category: Interchange Schedule Ramping Requirements
Average Score: 15
Orig #: 50

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Priority 3 – Low Priority Issues

Group 8
Category: **Transmission Service**
Sub-Category: Transmission Service Procurement & Settlement
Score: 17
Orig #: 6, 28, 33, 67, 117

Group 9
Category: **Planning**
Sub-Category: NA
Score: 18
Orig #: 26, 46, 57, 114

Group 10
Category: **Market Design**
Sub-Category: Reactive Power Compensation
Score: 18
Orig #: 16

Group 11
Category: **Market Monitoring/ Compliance**
Sub-Category: NA
Score: 19
Orig #: 11

Group 12
Category: **Market Design**
Sub-Category: Green Power Market
Score: 21
Orig #: 113

Currently Being Addressed by WEQ

Group 13
Category: **Market Standards**
Sub-Category: Physical and/or Financial Resolution of Inadvertent Interchange
Average Score: 16
Orig #: 14

Group 14
Sub-Category: Unscheduled/Parallel Path Flow Management
Score: NA
Orig #: 13, 15, 29, 134, 142

Seams Catalog Priority Summary
April 19, 2004

Priority 1 – WEQ Should Address in 2004

Category: Transmission Service
Sub-Category: Transmission Market Standard Product Definitions and Priorities
Average Score: 12
Orig #: 4, 103, 141

Category: Congestion Management
Sub-Category: All
Average Score: 13
Orig #: 9, 35, 36, 138

Category: Market Standards
Sub-Category: Energy Market Standard Product Definitions
Average Score: 14
Orig #: 3, 10, 25, 34, 42, 139

Category: Transaction Scheduling
Sub-Category: Interchange Scheduling Standardized Protocols
Average Score: 14
Orig #: 8, 12, 41, 78, 79, 104, 106 20

Priority 2 – WEQ Should Address in 2005

Category: Market Standards
Sub-Category: Market Standard Communication Protocols and Transparency
Average Score: 15
Orig #: 52, 140

Category: Market Standards
Sub-Category: Market Standard Operating Time
Average Score: 15
Orig #: 1

Category: System Reliability
Sub-Category: Interchange Schedule Ramping Requirements
Average Score: 15
Orig #: 50

Category: Market Standards
Sub-Category: Physical and/or Financial Resolution of Inadvertent Interchange
Average Score: 16
Orig #: 14

Priority 3 – WEQ Should Not Address

Category: Transmission Service
Sub-Category: Transmission Service Procurement & Settlement
Score: 17
Orig #: 6, 28, 33, 67, 117

Category: Planning
Sub-Category: NA
Score: 18
Orig #: 26, 46, 57, 114

Category: Market Design
Sub-Category: Reactive Power Compensation
Score: 18
Orig #: 16

Category: Market Monitoring/ Compliance
Sub-Category: NA
Score: 19
Orig #: 11

Category: Market Design
Sub-Category: Green Power Market
Score: 21
Orig #: 113

Currently Being Addressed by WEQ

Sub-Category: Unscheduled/Parallel Path Flow Management
Score: NA
Orig #: 13, 15, 29, 134, 142

Summary of Comments Received on Prioritization of Issues

Seams Issues Matrix

(Limited to potential business practice issues)

Updated April 16, 2004

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Resp Org WEQ EC	Issue Type	Resp Org JIC	Currently Being Addressed	Submitter	Consumers Prorities	Entergy Priorities	IRC Priorities	ITC Priority	PSEG Priority	ATC Priority	SRP Priorities	WE Energy Priority	Priority Totals	
36	Congestion Management	Congestion Management Market Coordination	Coordinate Hedging Instruments at Market Interfaces	Coordination of market based congestion hedging instruments, such as FTRs, between adjacent RTOs with markets, especially for out and thru' transactions		NAESB	National	Undecided		Raj Rana - AEP	1	2	3	1	1	1	3	1	13	13
35	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Locational Marginal Prices (LMP) at borders of RTOs with markets (Price cap included)		NAESB	National	Undecided		Raj Rana - AEP	1	2	3	1	1	1	3	1	13	
138	Congestion Management	Congestion Management Market Coordination		Coordination of congestion	Several regional efforts are underway. Coordinate practices and methods between areas with different market approaches.	NAESB	National	NAESB	Yes	Karl Tammar - ISO/RTO Council	1	2	2	1	1	2	2	1	12	
9	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		Transmission Calculations	Transmission calculations are not consistent. Solution: Standardized ATC Calculations.	NAESB	National	Undecided	Yes - SSG - WI	Steven Cobb - SRP	3	3	2	1	1	1	1	2	14	
113	Market Design	Green Power Market		Green power attributes trading		NAESB	National	Undecided	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	3	3	3	2	3	2	3	2	21	20
16	Market Design	Transmission Ancillary Service Market Design and Coordination	Reactive Power Compensation	Compensation for Reactive Power	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering.	NAESB	National	Undecided	Yes / IIPTF	Mark Lively - Lively Utility	3	3	3	1	1	2	3	2	18	18
11	Market Monitoring/ Compliance	Market Monitoring Entity Requirements		Market Oversight	New and mature markets need oversight to ensure that existing rules are complied with and new rules are adequate in meeting the scenarios they were designed to govern. Solution: Independent Market Auditor or Monitor.	Multiple	Regional	Multiple	Yes - SSG - WI	Steven Cobb - SRP	3	2	3	2	3	2	2	2	19	19
10	Market Standards	Energy Market Standard Product Definitions		Energy Products	Entities have disagreements concerning the definitions of various energy products. Solution: Standardized Energy Products.	NAESB	National	NAESB	Yes - WECC	Steven Cobb - SRP	3	2	1	1	2	1	1	2	13	14
3	Market Standards	Energy Market Standard Product Definitions		Definition & treatment of Firm/nonfirm Power	Annual Plan Item 4ci moved from MOS	NAESB	National	Undecided	No	Lou Oberski - Dominion Energy	3	2	1	2	2	1	1	2	14	
25	Market Standards	Energy Market Standard Product Definitions		Need for common physical market and products - regional variations permitted		NAESB	National	NAESB	No	Linda Horn - WE Energies	3	2	1	2	2	1	1	2	14	
34	Market Standards	Energy Market Standard Product Definitions		Clarification of Product Definitions	Complete/Standard definitions for Liquidated Damages (LD), "Into", etc.	NAESB	National	NAESB	No	Tony Reed - Southern	3	2	1	2	2	1	1	2	14	
139	Market Standards	Energy Market Standard Product Definitions		Standard definition of energy products	Energy products and services have common attributes in all markets. Standards definitions will improve efficiencies in communicating and operating between areas with various market designs	NAESB	National	NAESB	Yes	Karl Tammar - ISO/RTO Council	3	2	1	2	2	1	1	2	14	
42	Market Standards	Market Standard Communication Protocols and Transparency		Data Visibility	Inability to view neighboring markets information through a common software such that this sometimes hinders Market Participants ability to complete business in a timely fashion.	NAESB	National	NAESB	Yes	Marjorie Perlman - Energy East	2	3	1	2	1	2	1	2	14	
52	Market Standards	Market Standard Communication Protocols and Transparency		Confidentiality of Data and Information Shared	Standards of Confidentiality would enhance the capability to resolve data sharing and information posting	NAESB	National	NAESB	Limited	Carl Monroe, Southwest Power Pool	2	3	3	2	1	1	2	1	15	16
140	Market Standards	Market Standard Communication Protocols and Transparency		Standard messaging protocols for market notifications	Market participants will benefit from common messaging protocols.	NAESB	National	NAESB	No	Karl Tammar - ISO/RTO Council	3	3	1	2	2	2	1	2	16	
1	Market Standards	Market Standard Operating Time		Non Standard Time Zone	The lack of a standard Time Zone causes Market Inefficiencies	NAESB	National	NAESB	No	Phil Cox - AEP	3	2	2	1	2	2	2	1	15	
14	Market Standards	Physical and/or Financial Resolution of Inadvertent Interchange		Compensation for Inadvertent Interchange	Lack of compensation lessens incentives for operators to solve problems. Explicit compensation for inadvertent interchange is necessary for appropriate definition of other products, in that such compensation ensures that the defined product is delivered.	NAESB	National	NAESB	Yes / IIPTF	Mark Lively - Lively Utility	3	3	1	2	1	2	3	1	16	
46	Planning	Transmission Expansion and Generator Interconnection Coordination	Generator Interconnection - Affected Systems	Generation Interconnection Studies	Generation Interconnections close to seam affects both areas	NAESB	National	Undecided	Limited	Carl Monroe, Southwest Power Pool	3	2	3	3	1	1	3	1	17	18
57	Planning	Transmission Expansion and Generator Interconnection Coordination	Generator Interconnection Transmission Requirements	Transmission interconnection procedures	Need consistent approach to treating merchant generation interconnection procedures with transmission	Multiple	Regional	Multiple	Northeast ISO	Joe Rossignoli National Grid	3	2	3	3	3	1	3	2	20	
114	Planning	Transmission Expansion and Generator Interconnection Coordination	Interregional Transmission Planning Procedures	Coordination of interregional planning including transmission facilities and generator interconnection procedures		Multiple	Regional	Undecided	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	3	2	3	3	1	1	3	2	18	

Adobe Document Assembly Page Numbering

Summary of Comments Received on Prioritization of Issues

Seams Issues Matrix

(Limited to potential business practice issues)

Updated April 16, 2004

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Resp Org WEQ EC	Issue Type	Resp Org JIC	Currently Being Addressed	Submitter	Consumers Priorities	Entergy Priorities	IRC Priorities	ITC Priority	PSEG Priority	ATC Priority	SRP Priorities	WE Energy Priority	Priority Totals	
26	Planning	Transmission Expansion and Generator Interconnection Coordination	Transmission Expansion Cost and Construction Responsibilities	Transmission expansion planning - coordination between systems and determine who is obligated to build and pay for improvements	Being reviewed by PJM/MISO.	Multiple	Regional	Multiple	Yes	Linda Horn - WE Energies	3	2	3	3	2	1	3	1	18	
50	System Reliability	Generation-Load Balance	Interchange Schedule Ramping Requirements	Schedule Ramp Management	Ramping standard differences across the seams hinder business	NAESB	National	Undecided	Limited	Carl Monroe, Southwest Power Pool	3	2	2	3	1	1	2	1	15	15
12	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Develop Electronic Scheduling	Interchange/Intrachange Scheduling Data Exchange	Current E-Tagging process is inadequate for exchanging reliability and market data within the Western Interconnection. Solution: Electronic Scheduling	NAESB	National	NAESB	Yes - WECC	Steven Cobb - SRP	3	2	1	2	3	2	1	1	15	
41	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Inter-Market Ramping Requirements Standardization	Scheduling Coordination (including Ramp Rates)	RTOs have different ramp rates and scheduling requirements that require Market Participants to complete multiple submissions for the same transaction.	NAESB	National	Undecided	Yes	Marjorie Perlman - Energy East	2	2	1	3	1	1	2	1	13	14
79	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Standardize Inter-Market Scheduling Timelines	Market Design - Day Ahead. Other Scheduling Requirements	Should the time intervals and submission times be synchronized to mitigate obstacles to inter-RTO trade? (Issue I.b.12)	NAESB	National	NAESB	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	2	2	1	2	1	3	1	1	13	
78	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Tools and Procedures to Accommodate Inter-Market Interchange Scheduling Requirements	Market Design - Day Ahead. Schedule Components	Can tools be developed for scheduling submission that assist the user in meeting any differences in protocols between RTOs? (Issue I.b.11)	NAESB	National	Undecided	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	2	2	1	2	1	3	1	2	14	
106	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Transaction Scheduling - Inconsistent information and market timing rules lead to uncertainty and risk that discourage the scheduling of some inter-regional transactions.		NAESB	National	NAESB	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	2	2	1	2	1	3	1	2	14	
104	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Transmission Checkout Failure - Operators curta transactions due to mismatched tag data, differer MW volumes, etc. The curtailment of transactions due to data incompatibility is disruptive to both the marketplace and the reliable operation of the grid.		NAESB	National	NAESB	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	2	2	1	2	1	3	2	2	15	
8	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Scheduling	Inconsistent procedures among entities. Solution: Western Interconnection Standardized Interchange Scheduling Protocols.	Multiple	Regional	Multiple	Yes - SSG - WI	Steven Cobb - SRP	2	2	1	2	3	3	1	2	16	
103	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Transmission Service - Market participants require consistent treatment of transmission products across multiple control areas to reduce perceived market risk, scheduling confusion and uncertainty.		NAESB	National	NAESB	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	1	2	1	2	1	1	1	1	10	13
4	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Definition & treatment of Firm/nonfirm Transmission	Annual Plan Item 4cii moved from MOS	NAESB	National	Undecided	No	Lou Oberski - Dominion Energy	1	2	1	2	2	2	1	2	13	
141	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Replacement of contract path with flow-based transmission service		Multiple	Regional	Multiple	No	Ed Davis - Entergy	3	2	1	1	3	1	3	2	16	
117	Transmission Service	Transmission Service Procurement	Common Reservation System for Market Interface Transmission ATC	Contract Tie Capacity - One Stop Shopping		NAESB	Regional	NAESB	No	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	3	3	2	2	1	2	1	2	16	17
6	Transmission Service	Transmission Service Procurement	Common Western Interconnection Wide OASIS	Transmission Access	No transmission market one stop shopping available for the Western Interconnection - entities can't find needed information to efficiently conduct business on a preschedule or real-time basis. Solution: Common OASIS Site needed.	Multiple	Regional	Undecided	Yes - Various Transmission Providers	Steven Cobb - SRP	3	3	2	1	3	2	1	2	17	
33	Transmission Service	Transmission Service Procurement	Intra-Hour Transmission Service Procurement	Standard for Purchasing of Intra-Hour Transmission	The ability to purchase transmission after the top of the hour when the transmission service is predetermined as available in prior hour.	NAESB	National	NAESB	No	Tony Reed - Southern	3	3	2	2	2	2	1	3	18	
67	Transmission Service	Transmission Service Procurement	Secondary Transmission Service Market Standardization	Market Design - Prior to Day Ahead. Primary Release Mechanism	There seems to be agreement here that a secondary market would be outside the RTO. If the resulting secondary market is not westwide, will coordination be needed? (Issue I.a.8)	Multiple	Regional	Multiple	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	3	2	2	2	3	3	1	3	19	
28	Transmission Service	Transmission Service Settlement	Consolidate Multiple Market Transmission Service Settlement Statements	Multiple transmission service charge invoicing	Being reviewed by PJM/MISO.	NAESB	National	NAESB	Yes	Linda Horn - WE Energies	2	3	2	3	3	1	2	1	17	
13	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Compensation for Unscheduled Flows of Electricity	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering	NAESB	National	Undecided	Yes / IIPTF	Mark Lively - Lively Utility	2	3	2	1	2	1	3	2	16	17

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Seams Issues Matrix

(Limited to potential business practice issues)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Resp Org WEQ EC	Issue Type	Resp Org JIC	Currently Being Addressed	Submitter	Consumers Priorities	Entergy Priorities	IRC Priorities	ITC Priority	PSEG Priority	ATC Priority	SRP Priorities	WE Energy Priority	Priority Totals	
15	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Compensation for Loop Flow	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering.	NAESB	National	Undecided	Yes / IIPTF	Mark Lively - Lively Utility	2	3	2	1	2	1	3	2	16	
29	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Allocation of transmission capacity on reciprocal flow gates amounts to transmission service without compensation. Legitimizes "parallel loop flow".		NAESB	National	Undecided		Dave Nick - DTE Energy	3	3	2	1	2	1	3	2	17	
134	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Compensation for parallel flows		NAESB	National	NAESB	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	3	3	2	1	2	1	3	2	17	
142	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Pricing for native load loop flow impacts		Multiple	Regional	Multiple	No	Ed Davis - Entergy	3	3	2	1	2	2	3	2	18	

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TAB 9
Proposed Standards – Coordinate Interchange Business Practices

- Recommendation
- Comments
- ESS Subcommittee Comments, Incorporating comments into the Recommendation

Recommendation

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

1. RECOMMENDED ACTION:

_X_ Accept as requested
___ Accept as modified below
___ Decline

EFFECT OF EC VOTE TO ACCEPT RECOMMENDED ACTION:

_X_ Change to Existing Practice
___ Status Quo

2. TYPE OF DEVELOPMENT/MAINTENANCE

Per Request:	**Per Recommendation:**
_X_ Initiation	_X_ Initiation
___ Modification	___ Modification
___ Interpretation	___ Interpretation
___ Withdrawal	___ Withdrawal
___ Principle	___ Principle
___ Definition	___ Definition
_X_ Business Practice Standard	_X_ Business Practice Standard
___ Document	___ Document
___ Data Element	___ Data Element
___ Code Value	___ Code Value
___ X12 Implementation Guide	___ X12 Implementation Guide
___ Business Process Documentation	___ Business Process Documentation

3. RECOMMENDATION

SUMMARY:

Accept as requested Business Practices that are consistent with the current version of NERC Policy 3, will complement NERC compliance templates associated with Policy 3, and will ultimately facilitate the implementation of the NERC Coordinate Interchange Reliability Standard currently under development as part of the NERC Standards process.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RECOMMENDED STANDARDS:

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

Background:
In light of the continuing restructuring of the Electric industry, and FERC's rulemakings 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. A request for the development of a NAESB Business Practice Standard representing the Business Practices in Policy 3 and complementing NERC's Coordinate Interchange Standard was submitted in June, 2003. This Standard was approved by the Joint Interface Committee (JIC) representatives from NERC, NAESB, and RTO/ISO and assigned to NAESB for development.

The Standard is being developed using the Functional Model as a basis for defining the "Functions" necessary for Bulk Electric System reliability but also facilitates the existing NERC Operating Policies for "Control Areas".

Introduction:

This Standard is being developed to identify market-supported processes to facilitate fair & "equitable" competitive interchange practices. This standard will provide the necessary data and arrangements to the Interchange Authority and all involved parties of the Request for Interchange (RFI) for an Interchange Transaction to take place between Sink and Source Balancing Authorities (BA). This standard is designed to implement the flow of data and approval mechanisms to facilitate Interchange. It is not intended to supercede existing tagging protocols, but rather will facilitate both existing ETAG or any replacement protocols needed to implement the functional model. It should be understood this Standard covers the front-end business arrangements and requirements for an Interchange Transaction to take place. Upon receiving all approvals from the Approval Entities, the IA will utilize appropriate NERC policies or standards to transition the Arranged Interchange to a Confirmed Interchange and finally the implementation of the Confirmed Interchange.

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 to an Arranged Interchange.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RFI Standard 1.2 Arranged Interchange – The state where completed and required information from the business arrangements are provided to and received by the Interchange Authority.

RFI Standard 1.3 Balancing Authority (BA) – The entity which performs the Balancing Function as defined by NERC. Until such time as the Balancing Authority becomes a certified Function under the NERC Functional Model, these duties shall be performed by the respective Control Area.

RFI Standard 1.4 Confirmed Interchange - The state where the Interchange Authority has verified the Arranged Interchange and is ready to submit it to the Balancing Authorities.

RFI Standard 1.5 Implemented Interchange- The state where the Balancing Authority enters the Confirmed Interchange into its area control error (ACE) equation.

RFI Standard 1.6 Implemented 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 1.7 Interchange Authority (IA) – The entity which performs the Interchange Function as defined by NERC. Until such time as the Interchange Authority becomes a certified Function under the NERC Functional Model, these duties shall be performed by the respective Tagging Authority for the sink Control Area for the requested Interchange.

RFI Standard 1.8 Interchange Transaction – A transaction representing the delivery of energy from a generator located within a Point of Receipt (POR) BA to a load located within a Point of Delivery (POD) BA.

RFI Standard 1.9 Market Adjustment – A desired modification to the energy and/or transmission profile during the Confirmed Interchange period.

RFI Standard 1.10 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 1.11 Point of Delivery BA – The Balancing Authority responsible for monitoring and/or controlling the load identified as the sink of an Interchange Transaction.

RFI Standard 1.12 Point of Receipt BA – The Balancing Authority responsible for monitoring and/or controlling the generation identified as the source of an Interchange Transaction.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RFI Standard 1.13 Reliability Authority- The entity which performs the Reliability Authority functions as defined by NERC. Until such time as the Reliability Authority becomes a certified Function under the NERC Functional Model, these duties shall be performed by the respective appropriate reliability entity.

RFI Standard 1.14 Reliability Period – The segment of time from when the IA has received the RFI from the requesting PSE to physical implementation (beginning of ramp time).

RFI Standard 1.15 Request For Interchange, RFI- Process of providing required data as defined in the NAESB RFI Datasheet to the IA for the purpose of implementing a bilateral Interchange Transaction.

RFI Standard 1.16 Requesting PSE – The PSE submitting the Request For Interchange (RFI). Under current policy this entity would be called the "Tag Author".

RFI Standard 1.17 Transaction Correction – Modifications to non-reliability data of a Request For Interchange (RFI) while in the Arranged Interchange period. This non-reliability data is located in the NAESB RFI Datasheet and is labeled as "correctable".

RFI Standard 1.18 Transmission Service Provider- Approves or denies transmission service requests from PSEs, Generator Owners, and LSEs. This entity also administers the transmission tariff and provides transmission service agreements.

Business Practices

RFI Standard 2.0 All requests to implement an Interchange Transaction shall be accomplished by the submission of a completed "Request For Interchange", RFI, to the Interchange Authority (IA). Upon receipt of the RFI, the IA shall immediately forward the RFI to all involved parties of the RFI.

RFI Standard 2.1 All energy purchase, energy sale, and Transmission service arrangements necessary to implement the completed RFI shall be performed during the Market Period.

RFI Standard 2.2 Until such time as other protocols are established by NERC and/or NAESB, submission of the completed RFI shall be in accordance with NERC Policy 3 Appendix 3A4.

RFI Standard 3.0 While any Purchasing Selling Entity (PSE) may act as the "Requesting PSE", it shall be the responsibility of the load serving Purchasing-Selling-Entity (PSE), or their designee, to ensure that the completed RFI has been submitted to the IA.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RFI Standard 4.0 A completed RFI shall contain, at a minimum, the required information specified in the most current version of the **NAESB RFI Datasheet** (attached).

RFI Standard 5.0 On behalf of the Requesting PSE, the IA shall verify approvals from all involved Approval Entities (e.g. TSP-for transmission reservations, BA-for ramping start/end times and rate, RA-reliability analysis, Generator/Load PSE) prior to being confirmed and implemented in accordance with the NERC Coordinate Interchange Standard.

RFI Standard 5.1 The Requesting PSE shall submit required RFI information and data in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetable** (attached).

RFI Standard 5.2 Until such time as other protocols are established by NERC and/or NAESB, timing requirements for the submission and approval of the completed RFI shall be in accordance with NERC Policy 3 Appendix 3A1.

RFI Standard 6.0 All requests for approval/validation of the completed RFI by the IA during the Arranged Interchange Period shall be assessed in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetable.** The results of that assessment shall be promptly communicated by the IA back to all involved parties.

RFI Standard 6.1 Any denial of a RFI request by any Approval Entity shall be communicated to the IA and Requesting PSE and accompanied by the reason for such denial.

RFI Standard 7.0 The IA shall be responsible for communicating changes on the status of the RFI to all involved parties of the RFI, including BAs, IAs, RAs, counterparty PSE (Generator or Load Serving), and the TSPs, and the PSEs holding the associated transmission rights necessary to support the transaction.

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.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

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 The PSE who created the RFI shall be allowed to submit a Transaction correction to the RFI during the Arranged Interchange Period in accordance with the **NAESB RFI Submission and Response Timetable**.

RFI Standard 9.1 Market adjustments made during the Confirmed Interchange Period by the PSE must be submitted to the IA who immediately communicates the revised request to all involved parties of the RFI. Timing of the approval assessment on the market adjustment by the Approval Entities shall be in accordance with the NAESB **RFI Submission and Response Timetable**. If denied by any Approval Entity, the original request remains valid.

RFI Standard 10.0 Each PSE submitting a RFI for an Interchange Transaction shall have, or arrange to have, personnel on site and immediately available 24 x 7 for notification of Interchange Transaction changes.

RFI Standard 10.1 These personnel shall be available from the beginning of the Market Period until the end of the Implementation Period.

RFI Standard 11.0 Energy accounting for all RFIs shall be accomplished via Implemented Interchange Block Accounting.

RFI Standard 12.0 Settlement of losses shall be either handled as financial or as payment in-kind.

RFI Standard 12.1 For losses handled as payment in-kind, the PSE shall communicate to the IA the mw losses and the entity the losses are with for each TSP along the transaction path.

RFI Standard 12.2 All bilateral transactions are equal and opposite in direction for a source and sink BA.

RFI Standard 13.0 Ramp rates shall be standard across the North American Interconnections.

RFI Standard 13.1 Ramp rate for the Eastern Interconnection shall be 10 minutes equally across the start and end times of the Transaction unless otherwise agreed to by all parties involved in the Transaction.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RFI Standard 13.2 Ramp rate for the Western Interconnection shall be 20 minutes equally across the start and end times of the Transaction unless otherwise agreed to by all parties involved in the Transaction.

RFI Standard 14.0 For Dynamic Transfer Transactions, the requirements shall be established by NERC.

See also Attachments:

- NAESB RFI Datasheet
- NAESB RFI Submission and Response Timetable

4. SUPPORTING DOCUMENTATION

a. Description of Request:

Request submitted by the NAESB Members of the Joint Interface Committee requesting complementary business practice standards to support NERC's Coordinate Interchange Business Practices Standard.

b. Description of Recommendation:

WEQ Standards Review Subcommittee

On 7/10/03, the WEQ Standards Review Subcommittee established the Coordinate Interchange Business Practices Task Force, which is charged with scoping issues and developing standards pursuant to Request No. R03013 to support the Coordinate Interchange Standards being developed by NERC.

WEQ Coordinate Interchange Business Practices Task Force

On 7/29/03, the CIBPTF began its scoping work by looking at both the work of NERC's Coordinate Interchange Standard Drafting Team and current NERC Policy 3 to identify areas within the policy that have market implications. The CIBPTF completed a scoping document that was sent out for industry comment on 8/19/03.

NAESB-NERC-IRC Joint Interface Committee

On 9/18/03 the Joint Interface Committee determined through a unanimous motion to forward Request R03013 to NAESB for development.

WEQ Coordinate Interchange Business Practices Task Force

The review of NERC Policy 3 concluded at the 10/27-28/03 Joint Meeting of the NERC Interchange Subcommittee, NERC Coordinate Interchange Standards Drafting Team, and NAESB CIBPTF.

WEQ Executive Committee

In early January 2004 the WEQ Executive Committee re-assigned the CIBP to report to the WEQ Electronic Scheduling Subcommittee, in recognition of the transition of the task force from scoping to standards drafting.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

WEQ Coordinate Interchange Business Practices Task Force

On 12/02/03 a strawman standard was begun, revised on 1/21/04, and further revised on 2/12/04.

WEQ Electronic Scheduling Subcommittee

On 2/17-18/04 the ESS considered the RFI standard and unanimously adopted the following motion:

> The ESS recommends to the EC the passage of the Coordinate Interchange Business Practice Standard as presented by the CIBPTF, and modified in the February 17-18, 2004 ESS meeting. The Recommended standard shall be posted for public comment until April 2, 2004 and considered at the May EC meeting. The ESS will review public comments on this proposed standard at its scheduled April 5-7 meeting and, if necessary, make recommendations to the EC regarding any modifications to the standard arising from that review.

c. Business Purpose:

The Business Practices will provide market participants with procedures for providing any necessary data for the analysis of interchange, as defined by NERC for reliability purposes, including data format and timing of data submittals.

d. Commentary/Rationale of Subcommittee(s)/Task Force(s):

The WEQ Electronic Scheduling Subcommittee found the Request For Interchange (RFI) Standard to be consistent with the current version of NERC Policy 3, will complement NERC compliance templates associated with Policy 3, and will ultimately facilitate the implementation of the NERC Coordinate Interchange Reliability Standard currently under development as part of the NERC Standards process.The Coordinate Interchange Business Practices Task Force (CIBPTF) and WEQ Electronic Scheduling Subcommittee met on the following days and to prepare the document and recommendation and all work papers may be found on the following web pages (http://naesb.org/weq/weq_cibp.asp and http://naesb.org/weq/weq_electronic_scheduling.asp):

• July 29, 2003	Conference Call	CIBPTF
• October 21, 2003	Conference Call	CIBPTF
• October 27-28, 2003	Meeting	CIBPTF
• December 2, 2003	Meeting	CIBPTF
• January 21, 2004	Meeting	CIBPTF
• February 17-18, 2004	Meeting	ESS

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 transaction 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 TRANSACTION 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 transaction 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 RAI.

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.

- Point of Receipt -POR (Correctable) – valid Point of Resource for scheduled Transmission Reservation.
- Point of Delivery - POD (Correctable) – valid Point of Delivery for scheduled Transmission Reservation.
- Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.
- Scheduling Entity(ies) (Correctable) – entities that are physically scheduling interchange on behalf of the TRANSMISSION PROVIDER in order to provide wheeling services.
- **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.
- Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.
- **POR and POD Profiles (Required)** – schedule of Energy Flow imported at the Point of Receipt and Exported at the Point of Delivery.
- **Transmission Reservation Number(s) (Required)** (Correctable) – reference to a particular transmission reservation being used to provide transmission capacity to support the transaction being described.
    - **Transmission Product (Required)** (Correctable) – Specifies the NERC Priority.
    - **Transmission Customer (Required)** (Correctable) – identifies the entity that purchased and holds the transmission reservation being presented for use.
    - **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.

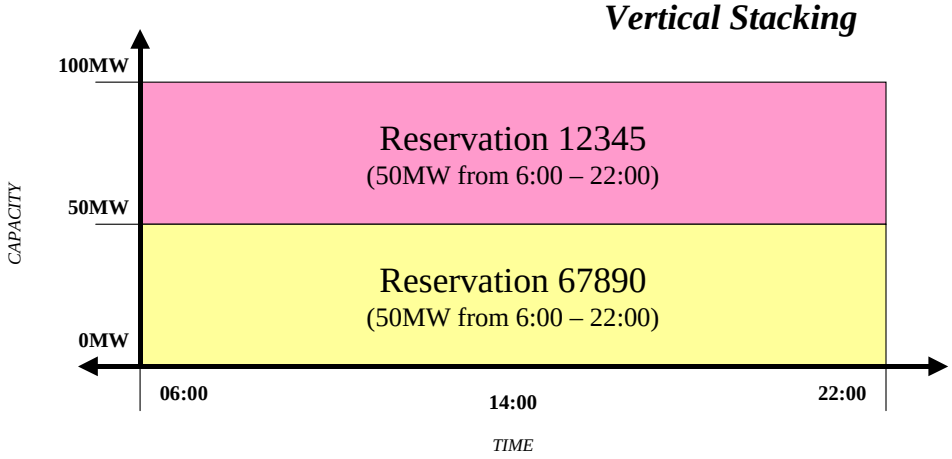
2.1.4 Using Multiple Transmission Reservations to Support a Single Leg of an Interchange Transaction

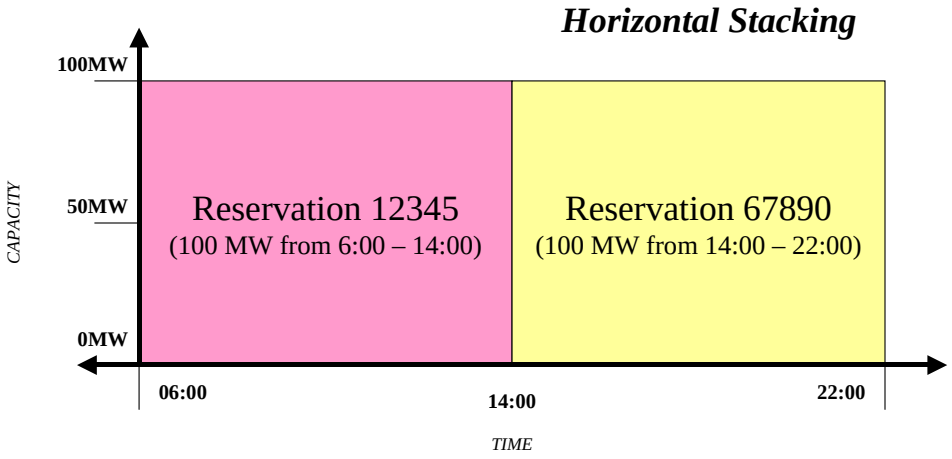
The use of multiple transmission reservations to support a single leg of an RFI is known as transmission **stacking**. There are two types of transmission stacking:

- 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





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 RAI'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 Timetable

Document Subsections

A. Eastern Interconnection – New Transactions
B. Western Interconnection – New Transactions
C. Interchange Transaction Corrections
D. Interchange Transaction Modifications

A. Eastern Interconnection – New Transactions

The table below represents the recommended business practices for RFI submission to the IA deadlines 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

Transaction Duration	PSE Submit Deadline*	Actual RFI Submission Time	Approval Entity Assessment Time	Time to Start of Transaction
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 TRANSACTION not the start of the ramp.				

B. Western Interconnection – New Transactions

The tables below represent the recommended business practices for RFI submission deadlines to the IA 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

Transaction Start/Submittal Time	PSE Submit Deadline	Actual RFI Submission Time*	Approval Entity Assessment Time	Approval/Denial Notes	Time to Start of Transaction*
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

B. Western Interconnection – New Transactions

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 Transaction will be assigned LATE composite status.**

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

C. Interchange Transaction Corrections

TRANSACTION 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 TRANSACTION 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 TRANSACTION.
- 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 TRANSACTION 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 TRANSACTION 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 Transaction not the start of the ramp.**	

D. Interchange Transaction Modifications

Market-initiated modifications, and other TRANSACTION 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 Transaction 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 Transaction not the start of the ramp.			

*See Special Exception for Cancellations below

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

D. Interchange Transaction Modifications

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 TRANSACTION **prior** to the start of a TRANSACTION but **following** that TRANSACTIONS approval. In the event that a PSE elects to cancel a TRANSACTION, 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 transaction 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 transaction 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 Transaction not the start of the ramp.**		

Comments

NAESB,

Please accept the following comments from Allegheny Power concerning Request No. R03013 - NAESB Coordinate Interchange Business Practice Standard (Request For Interchange, RFI):

Allegheny Power agrees that the standard accurately represents the business practices inherent in NERC Policy 3.

Allegheny Power believes that the standard, as written, will allow for the continuation of the E-Tag process.

Allegheny Power believes that the standard will appropriately facilitate the implementation of the NERC Functional Model.

In addition to the above issues, Allegheny Power wishes to introduce the issue of Resource Service Points as referenced in the NAESB RFI Datasheet A.2.1.1.1 and A.2.1.3.1. The expansions of RTOs/Markets have led to the decreased granularity of Resource Service Points. This in turn has made it increasing difficult to accurately determine the effect of Interchange Transactions on System Operating Limits. The result, in instances where there is a lack of generation available for re-dispatch in the local area, has been increasing reliance on dropping local load as a loading relief methodology instead of being able to correctly identify the interchange transactions that most significantly impact the System Operating Limit in question. Allegheny Power requests this business practice address the need for increasing the required granularity of Resource Service Points. Allegheny Power recognizes that this is a reliability issue and that NAESB may not be the proper venue for this discussion. However, since the issue of granularity is included in this business practice standard, we feel compelled to introduce this issue. We ask that this issue be forwarded to the proper venue if it is deemed that NAESB and this business standard is not the proper place for this discussion.

Thanks,
Bill

William J. Smith
Transmission Policy Consultant
Allegheny Power
Email: wsmith1@alleghenypower.com
Phone: (724) 838-6552
Fax: (724) 838-6156

These are the comments from BPA Transmission as listed below.

Shirley M. Buckmier - BPAT

-----Original Message-----
From: Buckmier, Shirley - TMS-DITT1
Sent: Friday, April 02, 2004 11:26 AM
To: 'Carter, Roman'
Cc: 'NAESB'
Subject: RE: Revised Naesb CIBP Standard (R03013)

Roman - thank you for calling and discussing this document with me. I agree with the changes that have been made since it was originally posted for comments. My main concern was to document Source BA and Sink BA and you have done that. Please consider this the comments from BPA Transmission and Seams Team.

I understand that our Power Business Line sent their comments in separately as they had some issues that effected them and not our Business Line.

Shirley Buckmier - BPAT
Transmission Technical Specialist - TMS

Comments from the Bonneville Power Administration, Power Business Line (BPA PBL) to the NAESB Recommendation R03013 (Coordinate Interchange Business Practices) are attached.

The BPA PBL appreciates the opportunity to comment on the NAESB CIBPS. Comments on the following items are italicized, underlined and in red within the original documents.

RFI Standard 1.0
RFI Standard 1.1
RFI Standard 1.12
RFI Standard 9.1
RFI Standard 9.2 (Added)
RFI Standard 12.0
RFI Standard 13.0
RFI Standard 14.0

RFI Submission and Response Timetable subsection B. Western Interconnection - New Transactions RFI Submission and Response Timetable subsection D. Interchange Transactions Modifications

RFI Datasheet 1.1.1.2.
RFI Datasheet 1.1.1.4. (Added)

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 transaction 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) ***(REQUIRED)*** ~~***(Correctable)***~~ – reference to a TRANSACTION entered into by the Energy Title Holder with one or more other participants in the RFI. ***The BPA PBL Would like to see generation contract numbers required for matching tags to specific financial agreements***

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

1.1.1.4. ***The BPA PBL would like to add the following as required information:***

Contact Information (REQUIRED) – 24-hour contact and/or preschedule/realtime information for all entities involved in a physical path (GPE, LSE, PSE, TSP, RA's and BA's)

2. Physical Information

2.1. **Physical Path (Required)** – the description of physically scheduling parties for the transaction 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 RAI.

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.

- Point of Receipt -POR (Correctable) – valid Point of Resource for scheduled Transmission Reservation.
- Point of Delivery - POD (Correctable) – valid Point of Delivery for scheduled Transmission Reservation.
- Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.
- Scheduling Entity(ies) (Correctable) – entities that are physically scheduling interchange on behalf of the TRANSMISSION PROVIDER in order to provide wheeling services.
- **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.
- Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.
- **POR and POD Profiles (Required)** – schedule of Energy Flow imported at the Point of Receipt and Exported at the Point of Delivery.
- **Transmission Reservation Number(s) (Required)** (Correctable) – reference to a particular transmission reservation being used to provide transmission capacity to support the transaction being described.
    - **Transmission Product (Required)** (Correctable) – Specifies the NERC Priority.
    - **Transmission Customer (Required)** (Correctable) – identifies the entity that purchased and holds the transmission reservation being presented for use.
    - **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.

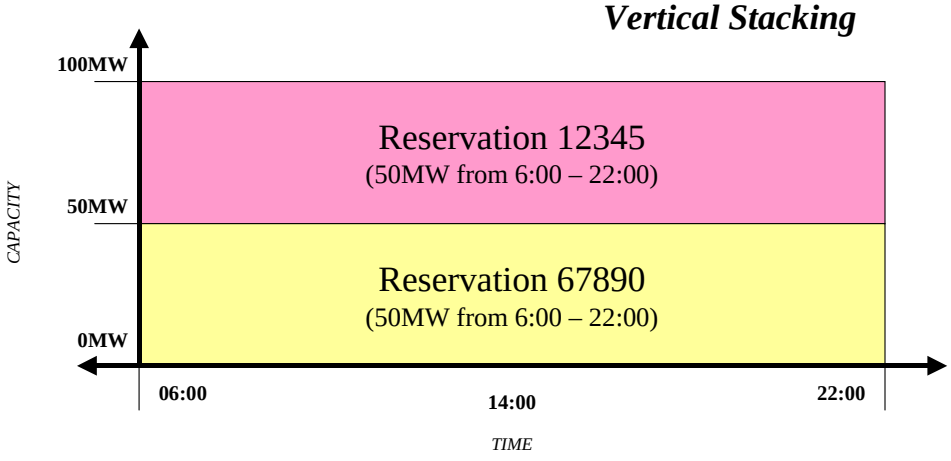
2.1.4 Using Multiple Transmission Reservations to Support a Single Leg of an Interchange Transaction

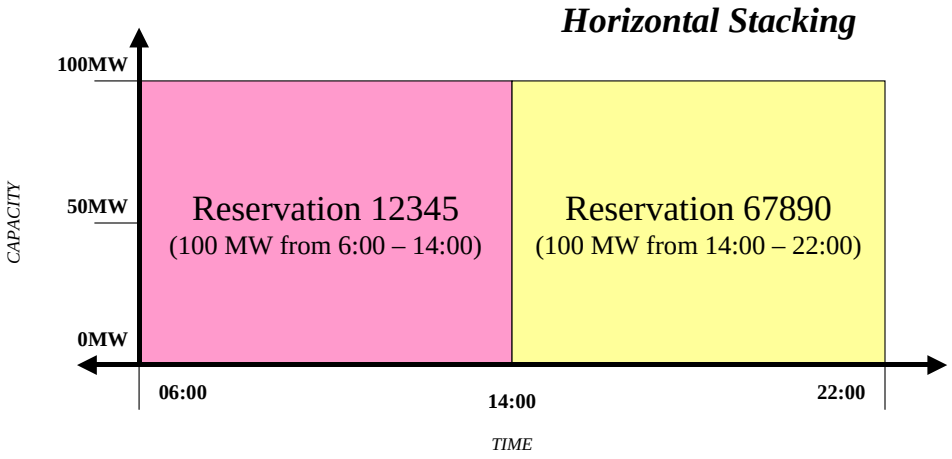
The use of multiple transmission reservations to support a single leg of an RFI is known as transmission **stacking**. There are two types of transmission stacking:

- 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





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 RAI'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.

Comments from the Bonneville Power Administration, Power Business Line (BPA PBL) to the NAESB Recommendation R03013 (Coordinate Interchange Business Practices) are attached.

The BPA PBL appreciates the opportunity to comment on the NAESB CIBPS. Comments on the following items are italicized, underlined and in red within the original documents.

RFI Standard 1.0
RFI Standard 1.1
RFI Standard 1.12
RFI Standard 9.1
RFI Standard 9.2 (Added)
RFI Standard 12.0
RFI Standard 13.0
RFI Standard 14.0

RFI Submission and Response Timetable subsection B. Western Interconnection - New Transactions RFI Submission and Response Timetable subsection D. Interchange Transactions Modifications

RFI Datasheet 1.1.1.2.
RFI Datasheet 1.1.1.4. (Added)

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

1. RECOMMENDED ACTION:

_X_ Accept as requested
___ Accept as modified below
___ Decline

EFFECT OF EC VOTE TO ACCEPT RECOMMENDED ACTION:

_X_ Change to Existing Practice
___ Status Quo

2. TYPE OF DEVELOPMENT/MAINTENANCE

Per Request:	**Per Recommendation:**
_X_ Initiation	_X_ Initiation
___ Modification	___ Modification
___ Interpretation	___ Interpretation
___ Withdrawal	___ Withdrawal
___ Principle	___ Principle
___ Definition	___ Definition
_X_ Business Practice Standard	_X_ Business Practice Standard
___ Document	___ Document
___ Data Element	___ Data Element
___ Code Value	___ Code Value
___ X12 Implementation Guide	___ X12 Implementation Guide
___ Business Process Documentation	___ Business Process Documentation

3. RECOMMENDATION

SUMMARY:

Accept as requested Business Practices that are consistent with the current version of NERC Policy 3, will complement NERC compliance templates associated with Policy 3, and will ultimately facilitate the implementation of the NERC Coordinate Interchange Reliability Standard currently under development as part of the NERC Standards process.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RECOMMENDED STANDARDS:

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

Background:
In light of the continuing restructuring of the Electric industry, and FERC's rulemakings 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. A request for the development of a NAESB Business Practice Standard representing the Business Practices in Policy 3 and complementing NERC's Coordinate Interchange Standard was submitted in June, 2003. This Standard was approved by the Joint Interface Committee (JIC) representatives from NERC, NAESB, and RTO/ISO and assigned to NAESB for development.

The Standard is being developed using the Functional Model as a basis for defining the "Functions" necessary for Bulk Electric System reliability but also facilitates the existing NERC Operating Policies for "Control Areas".

Introduction:

This Standard is being developed to identify market-supported processes to facilitate fair & "equitable" competitive interchange practices. This standard will provide the necessary data and arrangements to the Interchange Authority and all involved parties of the Request for Interchange (RFI) for an Interchange Transaction to take place between Sink and Source Balancing Authorities (BA). This standard is designed to implement the flow of data and approval mechanisms to facilitate Interchange. It is not intended to supercede existing tagging protocols, but rather will facilitate both existing ETAG or any replacement protocols needed to implement the functional model. It should be understood this Standard covers the front-end business arrangements and requirements for an Interchange Transaction to take place. Upon receiving all approvals from the Approval Entities, the IA will utilize appropriate NERC policies or standards to transition the Arranged Interchange to a Confirmed Interchange and finally the implementation of the Confirmed Interchange.

Definitions

RFI Standard 1.0 For the purposes of this Standard, the following definitions shall be applied:
The BPA PBL agrees with the WECC's request for NAESB "to ensure that the NERC and NAESB Standard definitions are the same".

RFI Standard 1.1 Approval Entities – Those entities responsible for providing approvals or denials to an Arranged Interchange. ***An Approval Entity should be responsible for any action taken, be that active/passive, or approval/denial.***

Deleted: active

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RFI Standard 1.2 Arranged Interchange – The state where completed and required information from the business arrangements are provided to and received by the Interchange Authority.

RFI Standard 1.3 Balancing Authority (BA) – The entity which performs the Balancing Function as defined by NERC. Until such time as the Balancing Authority becomes a certified Function under the NERC Functional Model, these duties shall be performed by the respective Control Area.

RFI Standard 1.4 Confirmed Interchange - The state where the Interchange Authority has verified the Arranged Interchange and is ready to submit it to the Balancing Authorities.

RFI Standard 1.5 Implemented Interchange- The state where the Balancing Authority enters the Confirmed Interchange into its area control error (ACE) equation.

RFI Standard 1.6 Implemented 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 1.7 Interchange Authority (IA) – The entity which performs the Interchange Function as defined by NERC. Until such time as the Interchange Authority becomes a certified Function under the NERC Functional Model, these duties shall be performed by the respective Tagging Authority for the sink Control Area for the requested Interchange.

RFI Standard 1.8 Interchange Transaction – A transaction representing the delivery of energy from a generator located within a Point of Receipt (POR) BA to a load located within a Point of Delivery (POD) BA.

RFI Standard 1.9 Market Adjustment – A desired modification to the energy and/or transmission profile during the Confirmed Interchange period.

RFI Standard 1.10 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 1.11 Point of Delivery BA – The Balancing Authority responsible for monitoring and/or controlling the load identified as the sink of an Interchange Transaction.

RFI Standard 1.12 Point of Receipt BA – The Balancing Authority responsible for monitoring and/or controlling the generation identified as the source of an Interchange Transaction. ***The BPA PBL agrees with the WECC and would suggest using Source BA and Sink BA as terms rather than POR/POD BA's in order to avoid confusion between transmission points and generation/load locations.***

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RFI Standard 1.13 Reliability Authority- The entity which performs the Reliability Authority functions as defined by NERC. Until such time as the Reliability Authority becomes a certified Function under the NERC Functional Model, these duties shall be performed by the respective appropriate reliability entity.

RFI Standard 1.14 Reliability Period – The segment of time from when the IA has received the RFI from the requesting PSE to physical implementation (beginning of ramp time).

RFI Standard 1.15 Request For Interchange, RFI- Process of providing required data as defined in the NAESB RFI Datasheet to the IA for the purpose of implementing a bilateral Interchange Transaction.

RFI Standard 1.16 Requesting PSE – The PSE submitting the Request For Interchange (RFI). Under current policy this entity would be called the "Tag Author".

RFI Standard 1.17 Transaction Correction – Modifications to non-reliability data of a Request For Interchange (RFI) while in the Arranged Interchange period. This non-reliability data is located in the NAESB RFI Datasheet and is labeled as "correctable".

RFI Standard 1.18 Transmission Service Provider- Approves or denies transmission service requests from PSEs, Generator Owners, and LSEs. This entity also administers the transmission tariff and provides transmission service agreements.

Business Practices

RFI Standard 2.0 All requests to implement an Interchange Transaction shall be accomplished by the submission of a completed "Request For Interchange", RFI, to the Interchange Authority (IA). Upon receipt of the RFI, the IA shall immediately forward the RFI to all involved parties of the RFI.

RFI Standard 2.1 All energy purchase, energy sale, and Transmission service arrangements necessary to implement the completed RFI shall be performed during the Market Period.

RFI Standard 2.2 Until such time as other protocols are established by NERC and/or NAESB, submission of the completed RFI shall be in accordance with NERC Policy 3 Appendix 3A4.

RFI Standard 3.0 While any Purchasing Selling Entity (PSE) may act as the "Requesting PSE", it shall be the responsibility of the load serving Purchasing-Selling-Entity (PSE), or their designee, to ensure that the completed RFI has been submitted to the IA.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RFI Standard 4.0 A completed RFI shall contain, at a minimum, the required information specified in the most current version of the **NAESB RFI Datasheet** (attached).

RFI Standard 5.0 On behalf of the Requesting PSE, the IA shall verify approvals from all involved Approval Entities (e.g. TSP-for transmission reservations, BA-for ramping start/end times and rate, RA-reliability analysis, Generator/Load PSE) prior to being confirmed and implemented in accordance with the NERC Coordinate Interchange Standard.

RFI Standard 5.1 The Requesting PSE shall submit required RFI information and data in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetable** (attached).

RFI Standard 5.2 Until such time as other protocols are established by NERC and/or NAESB, timing requirements for the submission and approval of the completed RFI shall be in accordance with NERC Policy 3 Appendix 3A1.

RFI Standard 6.0 All requests for approval/validation of the completed RFI by the IA during the Arranged Interchange Period shall be assessed in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetable.** The results of that assessment shall be promptly communicated by the IA back to all involved parties.

RFI Standard 6.1 Any denial of a RFI request by any Approval Entity shall be communicated to the IA and Requesting PSE and accompanied by the reason for such denial.

RFI Standard 7.0 The IA shall be responsible for communicating changes on the status of the RFI to all involved parties of the RFI, including BAs, IAs, RAs, counterparty PSE (Generator or Load Serving), and the TSPs, and the PSEs holding the associated transmission rights necessary to support the transaction.

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.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RFI Standard 9.0 The PSE who created the RFI shall be allowed to submit a Transaction correction to the RFI during the Arranged Interchange Period in accordance with the **NAESB RFI Submission and Response Timetable**.

RFI Standard 9.1 Market adjustments made during the Confirmed Interchange Period by the PSE must be submitted to the IA who immediately communicates the revised request to all involved parties of the RFI. Timing of the approval assessment on the market adjustment by the Approval Entities shall be in accordance with the NAESB **RFI Submission and Response Timetable**. If denied by any Approval Entity, the original request remains valid. ***The BPA PBL does not recognize a need for separate timelines for new transactions, corrections or modification within the Western Interconnect. BPA PBL recommends stream lining the timing requirements into one table in order to avoid confusion. (see RFI Submission and Response Timetable subsection D).***

RFI Standard 9.2 The BPA PBL agrees with the WECC in adding an RFI Standard 9.2 "Curtailment Requests for reliability reasons are not to be denied. Further language that accommodates reliability curtailments may need to be added to this standard"

RFI Standard 10.0 Each PSE submitting a RFI for an Interchange Transaction shall have, or arrange to have, personnel on site and immediately available 24 x 7 for notification of Interchange Transaction changes.

RFI Standard 10.1 These personnel shall be available from the beginning of the Market Period until the end of the Implementation Period.

RFI Standard 11.0 Energy accounting for all RFIs shall be accomplished via Implemented Interchange Block Accounting.

RFI Standard 12.0 Settlement of losses shall be either handled as financial or as payment in-kind***, or as defined in a FERC approved Tariff***.

RFI Standard 12.1 For losses handled as payment in-kind, the PSE shall communicate to the IA the mw losses and the entity the losses are with for each TSP along the transaction path.

RFI Standard 12.2 All bilateral transactions are equal and opposite in direction for a source and sink BA.

RFI Standard 13.0 Ramp rates shall be standard ***within*** the North American Interconnections***, as stated in RFI Standard 13.1 and 13.2 for the Eastern and Western interconnects.***

Deleted: ***across***

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RFI Standard 13.1 Ramp rate for the Eastern Interconnection shall be 10 minutes equally across the start and end times of the Transaction unless otherwise agreed to by all parties involved in the Transaction.

RFI Standard 13.2 Ramp rate for the Western Interconnection shall be 20 minutes equally across the start and end times of the Transaction unless otherwise agreed to by all parties involved in the Transaction.

RFI Standard 14.0 For Dynamic Transfer Transactions, the requirements shall be established by NERC***, except where regional differences are approved.***
The BPA PBL agrees with the WECC's suggested language

See also Attachments:

- NAESB RFI Datasheet
- NAESB RFI Submission and Response Timetable

4. SUPPORTING DOCUMENTATION

a. Description of Request:

Request submitted by the NAESB Members of the Joint Interface Committee requesting complementary business practice standards to support NERC's Coordinate Interchange Business Practices Standard.

b. Description of Recommendation:

WEQ Standards Review Subcommittee

On 7/10/03, the WEQ Standards Review Subcommittee established the Coordinate Interchange Business Practices Task Force, which is charged with scoping issues and developing standards pursuant to Request No. R03013 to support the Coordinate Interchange Standards being developed by NERC.

WEQ Coordinate Interchange Business Practices Task Force

On 7/29/03, the CIBPTF began its scoping work by looking at both the work of NERC's Coordinate Interchange Standard Drafting Team and current NERC Policy 3 to identify areas within the policy that have market implications. The CIBPTF completed a scoping document that was sent out for industry comment on 8/19/03.

NAESB-NERC-IRC Joint Interface Committee

On 9/18/03 the Joint Interface Committee determined through a unanimous motion to forward Request R03013 to NAESB for development.

WEQ Coordinate Interchange Business Practices Task Force

The review of NERC Policy 3 concluded at the 10/27-28/03 Joint Meeting of the NERC Interchange Subcommittee, NERC Coordinate Interchange Standards Drafting Team, and NAESB CIBPTF.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

WEQ Executive Committee

In early January 2004 the WEQ Executive Committee re-assigned the CIBP to report to the WEQ Electronic Scheduling Subcommittee, in recognition of the transition of the task force from scoping to standards drafting.

WEQ Coordinate Interchange Business Practices Task Force

On 12/02/03 a strawman standard was begun, revised on 1/21/04, and further revised on 2/12/04.

WEQ Electronic Scheduling Subcommittee

On 2/17-18/04 the ESS considered the RFI standard and unanimously adopted the following motion:

> The ESS recommends to the EC the passage of the Coordinate Interchange Business Practice Standard as presented by the CIBPTF, and modified in the February 17-18, 2004 ESS meeting. The Recommended standard shall be posted for public comment until April 2, 2004 and considered at the May EC meeting. The ESS will review public comments on this proposed standard at its scheduled April 5-7 meeting and, if necessary, make recommendations to the EC regarding any modifications to the standard arising from that review.

c. Business Purpose:

The Business Practices will provide market participants with procedures for providing any necessary data for the analysis of interchange, as defined by NERC for reliability purposes, including data format and timing of data submittals.

d. Commentary/Rationale of Subcommittee(s)/Task Force(s):

The WEQ Electronic Scheduling Subcommittee found the Request For Interchange (RFI) Standard to be consistent with the current version of NERC Policy 3, will complement NERC compliance templates associated with Policy 3, and will ultimately facilitate the implementation of the NERC Coordinate Interchange Reliability Standard currently under development as part of the NERC Standards process.The Coordinate Interchange Business Practices Task Force (CIBPTF) and WEQ Electronic Scheduling Subcommittee met on the following days and to prepare the document and recommendation and all work papers may be found on the following web pages (http://naesb.org/weq/weq_cibp.asp and http://naesb.org/weq/weq_electronic_scheduling.asp):

• July 29, 2003	Conference Call	CIBPTF
• October 21, 2003	Conference Call	CIBPTF
• October 27-28, 2003	Meeting	CIBPTF
• December 2, 2003	Meeting	CIBPTF
• January 21, 2004	Meeting	CIBPTF
• February 17-18, 2004	Meeting	ESS

Comments from the Bonneville Power Administration, Power Business Line (BPA PBL) to the NAESB Recommendation R03013 (Coordinate Interchange Business Practices) are attached.

The BPA PBL appreciates the opportunity to comment on the NAESB CIBPS. Comments on the following items are italicized, underlined and in red within the original documents.

RFI Standard 1.0
RFI Standard 1.1
RFI Standard 1.12
RFI Standard 9.1
RFI Standard 9.2 (Added)
RFI Standard 12.0
RFI Standard 13.0
RFI Standard 14.0

RFI Submission and Response Timetable subsection B. Western Interconnection - New Transactions RFI Submission and Response Timetable subsection D. Interchange Transactions Modifications

RFI Datasheet 1.1.1.2.
RFI Datasheet 1.1.1.4. (Added)

NAESB RFI Submission and Response Timetable

Document Subsections

A. Eastern Interconnection – New Transactions
B. Western Interconnection – New Transactions
C. Interchange Transaction Corrections
D. Interchange Transaction Modifications

A. Eastern Interconnection – New Transactions

The table below represents the recommended business practices for RFI submission to the IA deadlines 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

Transaction Duration	PSE Submit Deadline*	Actual RFI Submission Time	Approval Entity Assessment Time	Time to Start of Transaction
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 TRANSACTION not the start of the ramp.				

B. Western Interconnection – New Transactions

The tables below represent the ~~***recommended***~~ business practices for RFI submission deadlines to the IA within the Western Interconnection. These are default requirements. The tables describe the various minimum submission and assessment timing requirements**.** ***The BPA PBL suggests removal of "recommended" in order to establish a uniform time line throughout the Western Interconnection.***

Table 2: Western Interconnection – Timing Requirements

Transaction Start/Submittal Time	PSE Submit Deadline	Actual RFI Submission Time*	Approval Entity Assessment Time	Approval/Denial Notes	Time to Start of Transaction*
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

B. Western Interconnection – New Transactions

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 Transaction will be assigned LATE composite status.**

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

C. Interchange Transaction Corrections

TRANSACTION 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 TRANSACTION 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 TRANSACTION.
- 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 TRANSACTION 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 TRANSACTION 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 Transaction not the start of the ramp.**	

D. Interchange Transaction Modifications

Market-initiated modifications, and other TRANSACTION 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. ***The BPA PBL does not recognize a need for separate timelines for Transaction Modifications within the Western Interconnect. BPA PBL recommends streamlining timetables 2,3 and 5 into one table in order to avoid confusion.***

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 Transaction 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 Transaction not the start of the ramp.			

*See Special Exception for Cancellations below

D. Interchange Transaction Modifications

**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 TRANSACTION **prior** to the start of a TRANSACTION but **following** that TRANSACTIONS approval. In the event that a PSE elects to cancel a TRANSACTION, 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 transaction 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 transaction 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 Transaction not the start of the ramp.		

Coordinated Interchange Business Practice Standard - Comments of Consumers Energy due April 2, 2004

Consumers Energy has reviewed the proposed standard and has the following comment:

There is a reference to an unidentified term "RAI" in Section 2.1.1.4 and elsewhere in the document. It appears that this reference should be to the defined term "RFI".

_____

Andrew C. Dotterweich
Transmission and Regulatory Strategies
Consumers Energy

----Original Message-----
From: Ed Davis, Entergy
Sent: Wednesday, April 14, 2004 1:53 PM
Subject: RE: [WEQ ESS Group Mailing] Latest version of the CIBP Standard

I will be unable to attend the Friday conference call and would like to get the following comment before the group, and posted on the NAESB website, for consideration of this proposed standard.

Entergy would like to express the following concern and suggest the following modifications to the proposed NAESB Coordinate Interchange Business Practice distributed by Roman Carter April 13, 2004.

Our concern is that the allotted time for those entities reviewing, approving and implementing transmission service schedules, as currently provided in NERC Policy 3 and its Appendices, may be reduced as a result of this proposed IBP standard. The potential time reduction is a result of the NERC CI standard introducing the Interchange Authority function between the "market" and "reliability" as depicted in the diagram at the end of this proposal, and the inclusion of the IA in this standard and the timing of the processes between the market and approving entities contained in this proposed NAESB CI standard. In particular, this proposal contains the following:

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).

To assure the Policy 3 timing is not lost, we suggest this standard be revised to have the "completed RFI" (to be consistent with Standard 2.0 above) be "submitted at the same time to the IA, all appropriate market participants and all appropriate Approval Entities", as shown below:

RFI Standard 5.0 The completed RFI shall be submitted at the same time to the IA, all appropriate market participants and all appropriate Approval Entities in accordance with the timing requirements of the most current version of the NAESB RFI Submission and Response Timetables (attached).

(Please note the phrase "(and all other entities)" has been deleted.)

Distribution of the completed RFI to all Approval Entities at the same time as it is distributed to the IA should ensure there is no delay in their receipt of the RFI caused by the IA, and that all Approval Entities have their full time allocation to review, approve and implement the RFI.

We suggest that these modifications are significant to the proper interaction between the NAESB and NERC Coordinate Interchange standards and the maintenance of task timing requirements between those requesting the use of the power system and the implementers of those requests. Entergy believes that those reviewing, approving and implementing transmission schedules should be able to continue using the existing process times contained in Policy 3 and its Appendices.

Thank you.

Ed

Edward Davis
Entergy Services, Inc

----Original Message-----
From: Dison, Joel
Sent: Wednesday, April 14, 2004 8:22 AM
Subject: RE: [WEQ ESS Group Mailing] Latest version of the CIBP Standard

Dear ESS

Yesterday, Roman Carter sent you a revised copy of the proposed Coordinate Interchange Business Practice Standard that represents modifications resulting from public comment and the ESS discussion of those comments. I strongly encourage each of you to review this revised standard proposal prior to our conference call on Friday. I believe there should be little or no controversy over this version and I believe as modified it should have universal acceptance (at least to the extent the original Policy 3 was acceptable). Assuming we are all comfortable with the new proposal, it will be necessary for the ESS to send word to the Executive Committee recommending that they consider this proposal in lieu of the one posted back in March. I have prepared a draft letter from the ESS to the EC to that regard. It is attached for your convenience. Thanks - talk to you on Friday.

PS. Remember, because this will be a conference call only, there should be no charge for participation.

Joel Dison Manager, Market Policy
Southern Company Generation and Energy Marketing

-----Original Message-----
From: weqess-owner@mail.naesb.org [mailto:weqess-owner@mail.naesb.org] On Behalf Of Carter, Roman
Sent: Tuesday, April 13, 2004 12:48 PM
To: weqess@naesb.org
Subject: [WEQ ESS Group Mailing] Latest version of the CIBP Standard

In preparation for this Friday's Conference Call, attached is the latest version of the NAESB CIBP Standard. Also attached is the version Todd sent to me for modification that can be used for comparison.

I assume Naesb will forward to the ESS Exploder information on the details of the 10am CST Conference Call to everyone shortly. Thanks for your participation in this Standard.

Roman Carter

Southern Company Generation

& Energy Marketing

ENTERGY SERVICES COMMENTS

NAESB DRAFT STANDARD R03013
Coordinate Interchange Business Practices

Ed Davis
Entergy Services, Inc.
4-1-04

I. DEFINITIONS – Comments

We recommend all defined terms used in other documents, standards, processes, or previously approved documents should not be repeated here but should be incorporated into this NAESB standard by reference only. Deleting from this standard terms that are defined in other documents will:

- Help facilitate the implementation of the Functional Model,
- Make this standard consistent with the Open Access Transmission Tariff,
- Facilitate the coordination of this standard with the NERC Coordinate Interchange Reliability Standard,
- Allow for the continuation of the E-Tag process and the defining documents for E-Tag 1.7, and
- Avoid future confusion and constant changes or uncertainty as terms under the control of other entities would require changes to this standard.

In particular, defined terms that should be removed from this standard include: Arranged Interchange, Balancing Authority, Confirmed Interchange, Implemented Interchange, Interchange Authority, Interchange Transaction, Reliability Authority, Reliability Period, Transmission Service Provider, and any terms defined in the E-Tag documents.

II. RFI Standard 5.0 should be deleted as it is a repeat of part of the NERC Coordinate Interchange Standard. RFI Standard 5.1 should be changed to 5.0, and 5.2 should be changed to 5.1.

III. Ramp rates specified in the draft should be changed to “default ramp rates” for each Interconnection.

IV. References to “dynamic transfers”, “dynamic schedules” and “dynamic pseudo-ties” should be deleted because of the existing industry turmoil on these subjects. Standards addressing these issues can be created in the future when the industry has coalesced on these issues.

V. Appendix 3A1.A should have the following words added to the standard after Table 1 which are in the existing NERC Operating Manual:

> Tag submission timing requirements are based on the duration of the TRANSACTION. Tags representing TRANSACTIONS that run for less that one day (24 hours) must be submitted at least 20 minutes prior to the start of the TRANSACTION (excluding ramp time). Tags representing TRANSACTIONS running for one day or more (24 hours or more) must be submitted at least four hours prior to the start. Tags submitted that meet these requirements shall be considered “on-time” by the E-Tag system and may be granted conditional approval. Tags 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 TRANSACTIONS without the proper tag.

Tag assessment timing requirements are based on the submission time of the tag, as well as the duration. Hourly tags submitted one hour or less prior to start must be evaluated in ten minutes. Hourly tags submitted more than one hour but less than four hours prior to start must be evaluated in 20 minutes. Tags with a duration of less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. Tags with a 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, TRANSACTIONS may be submitted to replace existing TRANSACTIONS with a lower transmission priority. The new TRANSACTION tag 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.

VI. Appendix 3A1.B should have the following words added to the standard after Table 2 which are in the existing NERC Operating Manual:

Notes/Clarification:

1. All clock times are in PPT.
2. Tags falling under the criteria in yellow are deemed pre-schedule tags.
3. Tags falling under the criteria in green are deemed real-time tags.
4. Pre-schedule tags submitted between 15:00 and 18:00 will be assigned LATE composite status.
5. Real-time tags submitted after 20 minutes prior to the start of the Transaction will be assigned LATE composite status.
***Start-time references are for start of the Transaction, not the start of the ramp.**

Tag submission timing requirements are based on the type and duration of the TRANSACTION. Tags representing TRANSACTIONS 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 TRANSACTION (excluding ramp time). Tags representing TRANSACTIONS that are pre-scheduled to start the next day must be submitted by 1500 PST the day prior to the day the TRANSACTION is to start. Tags submitted that meet these requirements shall be considered “on-time” by the E-Tag system and may be granted conditional approval. Tags 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. This provision shall not be used to schedule TRANSACTIONS without the proper tag.

Tag assessment timing requirements are based on the submission time of the tag, as well as the duration. Hourly tags submitted one hour or less prior to start must be evaluated in ten minutes. Hourly tags submitted more than one hour but less than four hours prior to start must be evaluated in 20 minutes. Tags with a duration of less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. Tags submitted for pre-scheduled service starting the next day or a future day must be evaluated in three hours.

Comments of the ISO/RTOs
NAESB Coordinate Interchange Business Practice Standard
(Request For Interchange, RFI)

The ISO/RTO Council (IRC) appreciates the opportunity to make comments on the NAESB proposal for Coordinate Interchange Business Practices. We believe that NAESB's attempt to move the industry toward the Functional Model is a good first step toward the future. In general, we support this document as a way to move the current NERC processes into the realm of NAESB. We believe that NAESB should look for opportunities to improve the process along the way, recognizing that NERC is moving rapidly to implement its Functional Model.

More specifically, we believe this document should be more focused on the Functional Model and less focused on the E-Tag system. We are concerned that these standards tend to be e-Tag-centric and tend to perpetuate the existing E-Tag infrastructure. While the introduction would seem to indicate otherwise, the document nevertheless makes several recommendations that seem closely tied to E-Tag. In all likelihood, this would work well in "physical" markets, but whether the standard would be effective in areas where financial markets exist or where financial markets abut physical markets requires further exploration. We would urge that any "hard links" to E-tag be removed from this document, and instead be created as a separate NAESB business practice. Such a split will allow these standards to support the ongoing development of OASIS Phase II. In the long run, it is expected that there will be a transition to some new systems, so NAESB should look for options that document what exists now but are flexible to accommodate new structures.

Items below in blue italics are IRC comments.

Definitions

RFI Standard 1.3 Interchange Transaction – A transaction representing the delivery of energy from a generator located within a Point of Resource (POR) BA to a load located within a Point of Delivery (POD) BA.

Should change Resource to Receipt to match current accepted industry definitions.

RFI Standard 1.4 Point of Resource BA – The Balancing Authority responsible for monitoring and/or controlling the generation identified as the source of an Interchange Transaction.

Should change Resource to Receipt to match current accepted industry definitions.

RFI Standard 1.8 Arranged Interchange – The state where completed and required information from the business arrangements are provided to and received by the Interchange Authority.

Isn't this the Arranged Interchange Period?

> **RFI Standard 1.12** Implemented 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.

Is there a reason this definition is applied only to Implemented Interchange? It would seem that the intent should be that any description of Interchange (Requested, Confirmed, or Implemented) should be described using a consistent conventions (at least with regard to RFIs). For example, it would not be expected for a PSE to submit an RFI in both Integrated Accounting to cover the Requested time frame and to have an IA or BA convert it to Block Accounting for use in the Implemented time frame. Perhaps just defining Block Accounting would help, and it could apply to the state of the transaction as appropriate.

RFI Standard 1.13 Market Adjustment – A desired modification to the energy and/or transmission profile during the Confirmed Interchange period.

As defined, it seems that a "market adjustment" that requires the purchase of additional transmission would not be supported. For example, if a PSE wanted to raise the level of a Confirmed Interchange transaction, but did not have the transmission to support it, there would be no ability to purchase that transmission. If the "market period" is redefined to include the arrangements needed to support an RFI or change to an existing RFI, this problem would be addressed. Can you clarify whether you could purchase additional transmission service on the fly?

Business Practices

RFI Standard 2.0 All requests to implement an Interchange Transaction shall be accomplished by the submission of a completed "Request For Interchange", RFI, to the Interchange Authority (IA). Upon receipt of the RFI, the IA shall immediately forward the RFI to all involved parties of the RFI.

There are two perceived submittals that need to occur. The first is during the Market Period where the PSE is handling the "commercial arrangements" necessary to attain a balanced schedule. This involves the submittal of a request to schedule to all affected parties (RA, BA TSP, etc). The second is the actual submission of the balanced schedule to the IA for confirmation and implementation during the Arranged Interchange Period. It doesn't seem clear in this section if the RFI can/will be used for both submissions or only for the submission of the balanced schedule to the IA. Some clarification is required. It is the IRC's opinion that this applies only to the submission of the balanced schedule to the IA.

RFI Standard 2.2 Until such time as other protocols are established by NERC and/or NAESB, submission of the completed RFI shall be in accordance with NERC Policy 3 Appendix 3A4.

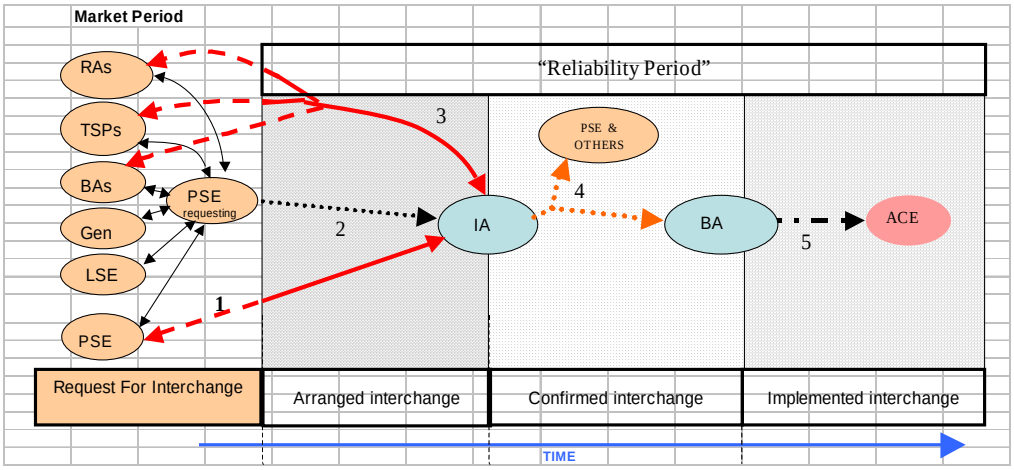
Standard 2.2 refers to the NERC definition of Tag Data. Standard 5.0 refers to the NAESB definition of RFI Data (which is equivalent to tag data). At a minimum, these two standards should be consolidated (similar to 5.1 and 5.2). However, it is probably more appropriate to simply delete standard 5. Coordination between NERC and NAESB should take place so that there is just one place for this information.

RFI Standard 3.0 While any Purchasing Selling Entity (PSE) may act as the "Requesting PSE", it shall be the responsibility of the load serving Purchasing-Selling-Entity (PSE), or their designee, to ensure that the completed RFI has been submitted to the IA.

This may not be adequate where Financial Markets are involved. A Marketer can "dump" energy into the spot market without any specific load serving commitment, they are simply offering energy in at a desired price. Consideration should be given to decoupling submitting the RFI from the obligation to serve load.

RFI Standard 4.0 A completed RFI shall contain, at a minimum, the required information specified in the most current version of the **NAESB RFI Datasheet** (attached).

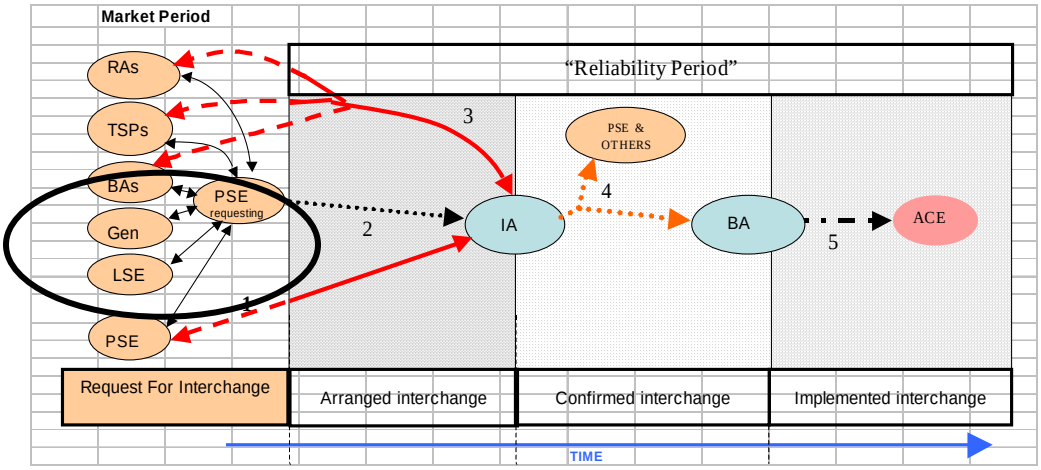
The information submitted to the IA needs to be determined by the minimum data set that the BA's need to implement the transaction in their ACE. This is not market sensitive information. Since the IA is obligated to supply only the necessary information a BA needs to take the transactions physical, the information should be determined under the NERC standard for IA to BA communication during the Confirmed Interchange Period. See diagram below.



RFI Standard 5.0 On behalf of the Requesting PSE, the IA shall verify approvals from all involved Approval Entities (e.g. TSP-for transmission reservations, BA-for ramping start/end times and rate, RA-reliability analysis, Generator/Load PSE) prior to being confirmed and implemented in accordance with the NERC Coordinate Interchange Standard.

The words "verify approvals" should be changed to "confirm approvals". Since the PSE is required to submit a balanced scheduled to the IA, the PSE has already obtained a set of preliminary approvals from all parties to the transaction. The IA function is simply to confirm all "reliability" parties (RA, TSP & BA) have in fact agreed to schedule the energy as specified and once confirmed, pass the schedule to the BA for implementation.

Also per the diagram there is no obligation for the IA to communicate with the Generator/Load PSE. Is there a necessity for this layer of communication to occur? See diagram below. There is no need for the IA to contact the Generators or LSEs.



RFI Standard 5.2 Until such time as other protocols are established by NERC and/or NAESB, timing requirements for the submission and approval of the completed RFI shall be in accordance with NERC Policy 3 Appendix 3A1.

Standards 5.1 and 5.2 appear to be in conflict. This document, by virtue of it being approved, supercedes the requirements defined in NERC Policy 3 Appendix 3A1. As such, 5.2 should be considered superfluous – as should NERC Appendix 3A1. Make sure the requirements are in just one place.

RFI Standard 6.0 All requests for approval/validation of the completed RFI by the IA during the Arranged Interchange Period shall be assessed in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetable.** The results of that assessment shall be promptly communicated by the IA back to all involved parties.

Arranged Interchange Period not defined in RFI Standard 1.0, only Market Period and Reliability Period are defined. Should include the definition in glossary.

RFI Standard 7.0 The IA shall be responsible for communicating changes on the status of the RFI to all involved parties of the RFI, including BAs, IAs, RAs, counterparty PSE (Generator or Load Serving), and the TSPs, and the PSEs holding the associated transmission rights necessary to support the transaction.

See previous comments about IA to Generator/Load PSE communication.

RFI Standard 9.0 The PSE who created the RFI shall be allowed to submit a Transaction correction to the RFI during the Arranged Interchange Period in accordance with the **NAESB RFI Submission and Response Timetable**.

This section is defining "corrections" not modifications. The PSE should only be able to correct information on an RAI when it is in the Arranged or Confirmed state. Once it is implemented and has gone physical, the only two options are; a curtailment for reliability or a market adjust, no "corrections" per se should be allowed once implemented. Some clarification to this section to clearly delineate what can happen and when may be appropriate.

RFI Standard 9.1 Market adjustments made during the Confirmed Interchange Period by the PSE must be submitted to the IA who immediately communicates the revised request to all involved parties of the RFI. Timing of the approval assessment on the market adjustment by the Approval Entities shall be in accordance with the NAESB **RFI Submission and Response Timetable**. If denied by any Approval Entity, the original request remains valid.

This section implies the PSE is the only entity that can perform a market adjust. If you look at some of the financial markets, a PSE has the option of offering price sensitive transactions, e.g., if the price is above the strike price provided, make the transaction happen. In theory the market operator/BA may adjust this transaction every hour (or less than one hour in some areas) based on their system economics. The section is too restrictive and should allow for other entities to issue market adjusts where appropriate.

Clarification is required for the statement "If denied by any Approval Entity, the original request remains valid". Is this meant to imply that any other hours of the request are still in effect and the denial would only apply to the hour in question?

RFI Standard 10.1 These personnel shall be available from the beginning of the Market Period until the end of the Implementation Period.

Standard 10 goes beyond existing NERC policy, in that it requires 24X7 marketer support as soon as an RFI is submitted for implementation – current Policy requires that marketers be available from the time they take possession of the energy (i.e., when flow

starts) to the time the energy delivery is completed (i.e., when flow ends). Is this an intentional change?

RFI Standard 11.0 Energy accounting for all RFIs shall be accomplished via Implemented Interchange Block Accounting.

Make sure this is flexible enough to handle 15 and 30 minutes interchange scheduling changes, the markets are pushing the industry to get off the old one hour block loading and look for 15 and/or 30 minute block loading.

RFI Standard 12.1 For losses handled as payment in-kind, the PSE shall communicate to the IA the mw losses and the entity the losses are with for each TSP along the transaction path.

Is the "communication" regarding losses in-kind to be handled through a separate RFI with each in-kind area?

RFI Standard 13.0 Ramp rates shall be standard across the North American Interconnections.

At a high level regarding this section, ramp rate is a function of the responsiveness of the BA's system, some units just don't move as fast as others plus the interaction of generators with loads where large MW delta's can occur as load comes in or goes out, sounds more like a reliability standard that NERC should develop for the BA's not NASEB. NAESB should not set standards for the MW volume of the ramp, only for the length of the ramp (10 minutes – from 5 before the hour until 5 after the hour, for example).

Regarding the details in this section, is it really a ramp standard or merely the default ramp rate? In principle we have allowed entities to go to "off nominal" ramp rates when mutually agreeable. Standards 13.1 and 13.2 are the current defaults but the way the section reads there is no flexibility to deviate. This Standard attempts to define a standard ramp, then goes on in Standards 13.1 and 13.2 to indicate deviations from the standard are acceptable. We believe it would be more appropriate to specify in Standard 13 that "ramps must be agreed to by the source and sink BAs," and not attempt to specify a standard that is not truly required.

Also the industry has traditionally referred to the ramp as a straddle ramp, i.e., 10 minutes over the start time. There is no mention of that in this section.

Datasheet

The RFI Datasheet contains a significant amount of data items that a number of RTOs are frankly not interested in. While we recognize that this standard is intended to support the existing systems, we encourage NAESB to move toward OASIS Phase II to remove these inefficiencies.

The RFI Submission and Response Time Table attempts to require specific submission request, evaluation, and processing times. While the IRC supports the general concept of setting a certain level of performance, we believe that the timing requirements for BA implementation of a schedule should be determined by NERC.

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

ISO NE:
Overall the draft is a good start. The one underline weakness is the standard is very E-tag centric and will in all likelihood work extremely well in "physical" markets. How well the standard will work in areas where financial markets exist or where financial markets abut physical markets needs further exploration.

Background:

In light of the continuing restructuring of the Electric industry, and FERC's rulemakings 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. Furthermore, NERC Operating Policies do not reflect the new organizations or merchant functions that are forming.

With regards to Policy 3, NERC currently is developing the Coordinate Interchange Standard to address the reliability issues associated with a bilateral interchange Transaction. 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:
A request for the development of a NAESB complementary Business Practice Standard to NERC's Coordinate Interchange Standard was submitted in June, 2003. This Standard was approved by the Joint Interface Committee (JIC) representatives from NERC, NAESB, and RTO/ISO and assigned to NAESB for development.

This Standard is being developed to identify market-supported processes to facilitate fair & "equitable" competitive interchange practices. This standard will provide the necessary data and arrangements to the Interchange Authority and all involved parties of the Request for Interchange (RFI) for an Interchange Transaction to take place between Sink and Source Balancing Authorities (BA). This standard is designed to implement the flow of data and approval mechanisms to facilitate Interchange. It is not intended to be the "Tagging Standard". NAESB's ESS is aware of the Industry desire to maintain a "Tagging" mechanism for the dissemination of data. The ESS will be the entity that will go forward with Tagging rules and procedures. The RFI shall contain at a minimum the required market and reliability information from the NAESB RFI Datasheet (attached). It should be understood this Standard covers the front-end business arrangements and requirements for an Interchange Transaction to take place. Upon receiving all approvals from the Approval Entities, the IA will utilize NERC's Coordinate Interchange Standard to transition the Arranged Interchange to a Confirmed Interchange and finally the implementation of the Confirmed Interchange.

The Standard is being developed using Functional Model definitions to provide consistency with NERC's Reliability Standards.

Definitions

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

RFI Standard 1.1 Balancing Authority (BA) – The entity which performs the Balancing Function. Some of the duties of the Balancing Function include integrating resource plans ahead of time, maintaining load-interchange-generation balance within a Balancing Authority Area, and supporting Interconnection frequency in real time. In today's operating environment with respect to Interchange, this entity closely resembles a Control Area. Until such time as the Balancing Authority becomes a certified Function under the NERC Functional Model, these duties shall be performed by the respective Control Area.

RFI Standard 1.2 Interchange Authority (IA) – The entity which performs the Interchange Function. Some of the duties of the Interchange Function include authorizing implementation of valid and balanced Interchange schedules between Balancing Authority areas, and ensuring Interchange Transactions are properly identified for reliability assessment purposes. Until such time as the Interchange Authority becomes a certified Function under the NERC Functional Model, these duties shall be performed by the respective Tagging Authority for the sink Control Area for the requested Interchange.

RFI Standard 1.3 Interchange Transaction – A transaction representing the delivery of energy from a generator located within a Point of Resource (POR) BA to a load located within a Point of Delivery (POD) BA.

ISO NE:
Should change Resource to Receipt

RFI Standard 1.4 Point of Resource BA – The Balancing Authority responsible for monitoring and/or controlling the generation identified as the source of an Interchange Transaction.

ISO NE:
Should change Resource to Receipt

RFI Standard 1.5 Point of Delivery BA – The Balancing Authority responsible for monitoring and/or controlling the load identified as the sink of an Interchange Transaction.

RFI Standard 1.6 Requesting PSE – The PSE submitting the Request For Interchange (RFI). Under current policy this entity would be called the "Tag Author".

RFI Standard 1.7 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 1.8 Arranged Interchange – The state where completed and required information from the business arrangements are provided to and received by the Interchange Authority.

ISO NE:
Isn't this the Arranged Interchange Period ?

RFI Standard 1.9 Confirmed Interchange - The state where the Interchange Authority has verified the Arranged Interchange and is ready to submit it to the Balancing Authorities.

RFI Standard 1.10 Implemented Interchange- The state where the Balancing Authority enters the Confirmed Interchange into its area control error (ACE) equation.

RFI Standard 1.11 Approval Entities – Those entities responsible for providing active approvals to an Arranged Interchange.

RFI Standard 1.12 Implemented 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 1.13 Market Adjustment – A desired modification to the energy and/or transmission profile during the Confirmed Interchange period.

RFI Standard 1.14 Transaction Correction – Modifications to non-reliability data of a Request For Interchange (RFI) while in the Arranged Interchange period. This non-reliability data is located in the NAESB RFI Datasheet and is labeled as "correctable".

RFI Standard 1.15 Reliability Period – The segment of time from when the IA has received the RFI from the requesting PSE to physical implementation (beginning of ramp time).

RFI Standard 1.16 Request For Interchange, RFI- Process of providing required data as defined in the NAESB RFI Datasheet to the IA for the purpose of implementing a bilateral Interchange Transaction.

RFI Standard 1.17 Transmission Service Provider- Approves or denies transmission service requests from PSEs, Generator Owners, and LSEs. This entity also administers the transmission tariff and provides transmission service agreements.

RFI Standard 1.18 Reliability Authority- Ensures the real-time operating reliability of the interconnected bulk electric transmission systems within a Reliability Authority area. Provides Interchange Transaction approvals to Interchange Authorities based on reliability analysis. Until such time as the Reliability Authority becomes a certified Function under the NERC Functional Model, these duties shall be performed by the respective Reliability Coordinator.

Business Practices

RFI Standard 2.0 All requests to implement an Interchange Transaction shall be accomplished by the submission of a completed "Request For Interchange", RFI, to the Interchange Authority (IA). Upon receipt of the RFI, the IA shall immediately forward the RFI to all involved parties of the RFI.

ISO NE:
There are two perceived submittals that need to occur. The first is during the Market Period where the PSE is handling the "commercial arrangements" necessary to attain a balanced schedule. This involves the submittal of a request to schedule to all affected parties (RA, BA TSP, etc). The second is the actual submission of the balanced schedule to the IA for confirmation and implementation during the Arranged Interchange Period. It doesn't seem clear in this section if the RFI can/will be used for both submissions or only for the submission of the balanced schedule to the IA. Some clarification is required.

RFI Standard 2.1 All energy purchase, energy sale, and Transmission service arrangements necessary to implement the completed RFI shall be performed during the Market Period.

RFI Standard 2.2 Until such time as other protocols are established by NERC and/or NAESB, submission of the completed RFI shall be in accordance with NERC Policy 3 Appendix 3A4.

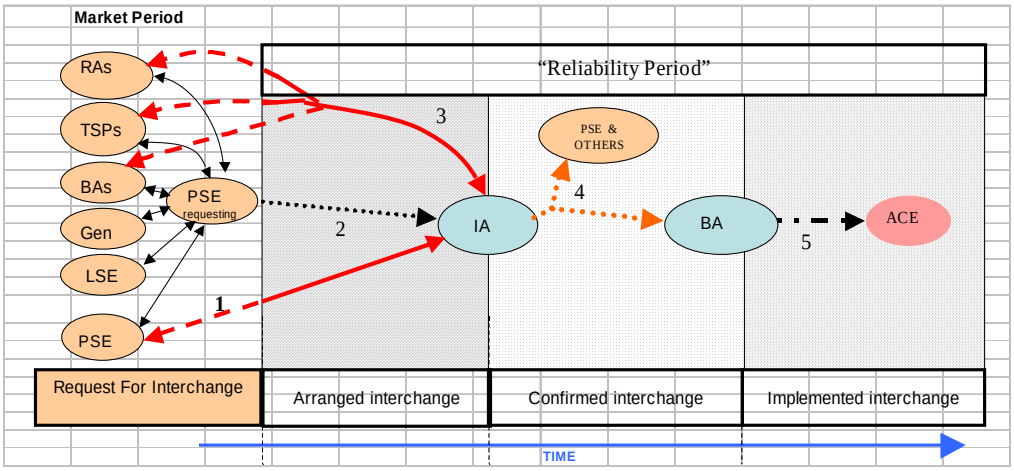
RFI Standard 3.0 While any Purchasing Selling Entity (PSE) may act as the "Requesting PSE", it shall be the responsibility of the load serving Purchasing-Selling-Entity (PSE), or their designee, to ensure that the completed RFI has been submitted to the IA.

ISO NE:
This may not be adequate where Financial Markets are involved. A Marketer can "dump" energy into the spot market without any specific load serving commitment,

they are simply offering energy in at a desired price. Consideration should be given to decoupling submitting the RFI from the obligation to serve load.

RFI Standard 4.0 A completed RFI shall contain, at a minimum, the required information specified in the most current version of the **NAESB RFI Datasheet** (attached).

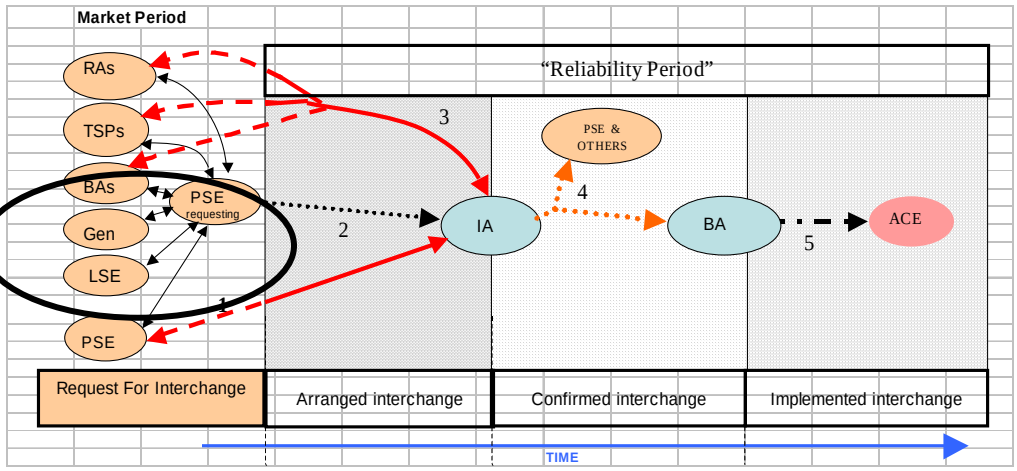
ISO NE:
The information submitted to the IA needs to be determined by the minimum data set that the BA's need to implement the transaction in their ACE. This is not commercial information. Since the IA is obligated to supply the necessary information a BA needs to take the transactions physical, the information should be determined under the NERC standard for IA to BA communication during the Confirmed Interchange Period. See diagram below.



RFI Standard 5.0 On behalf of the Requesting PSE, the IA shall verify approvals from all involved Approval Entities (e.g. TSP-for transmission reservations, BA-for ramping start/end times and rate, RA-reliability analysis, Generator/Load PSE) prior to being confirmed and implemented in accordance with the NERC Coordinate Interchange Standard.

ISO NE:
The words "verify approvals" should be changed to "confirm approvals". Since the PSE is required to submit a balanced scheduled to the IA, the PSE has already obtained a set of preliminary approvals from all parties to the transaction. The IA function is simply to confirm all "reliability" parties (RA, TSP & BA) have in fact agreed to schedule the energy as specified and once confirmed, pass the schedule to the BA for implementation.

Also per the diagram there is no obligation for the IA to communicate with the Generator/Load PSE. Is there a necessity for this layer of communication to occur ? See diagram below.



RFI Standard 5.1 The Requesting PSE shall submit required RFI information and data in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetable** (attached).

RFI Standard 5.2 Until such time as other protocols are established by NERC and/or NAESB, timing requirements for the submission and approval of the completed RFI shall be in accordance with NERC Policy 3 Appendix 3A1.

RFI Standard 6.0 All requests for approval/validation of the completed RFI by the IA during the Arranged Interchange Period shall be assessed in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetable.** The results of that assessment shall be promptly communicated by the IA back to all involved parties.

ISO NE:
Arranged Interchange Period not defined in RFI Standard 1.0, only Market Period and Reliability Period are defined. Should include the definition in glossary.

RFI Standard 6.1 Any denial of a RFI request by any Approval Entity shall be communicated to the IA and Requesting PSE and accompanied by the reason for such denial.

RFI Standard 7.0 The IA shall be responsible for communicating changes on the status of the RFI to all involved parties of the RFI, including BAs, IAs, RAs, counterparty PSE (Generator or Load Serving), and the TSPs, and the PSEs holding the associated transmission rights necessary to support the transaction.

ISO NE:

See previous comments about IA to Generator/Load PSE communication.

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 The PSE who created the RFI shall be allowed to submit a Transaction correction to the RFI during the Arranged Interchange Period in accordance with the **NAESB RFI Submission and Response Timetable**.

ISO NE:
This section is defining "corrections" not modifications. The PSE should only be able to correct information on an RAI when it is in the Arranged or Confirmed state. Once it is implemented and has gone physical, the only two options are; a curtailment for reliability or a market adjust, no "corrections" per se should be allowed once implemented. Some clarification to this section to clearly delineate what can happen and when may be appropriate.

RFI Standard 9.1 Market adjustments made during the Confirmed Interchange Period by the PSE must be submitted to the IA who immediately communicates the revised request to all involved parties of the RFI. Timing of the approval assessment on the market adjustment by the Approval Entities shall be in accordance with the NAESB **RFI Submission and Response Timetable**. If denied by any Approval Entity, the original request remains valid.

ISO NE:
This section implies the PSE is the only entity that can perform a market adjust. If you look at some of the financial markets, a PSE has the option of offering price sensitive transactions, e.g., if the price is above the strike price provided, make the transaction happen. In theory the market operator/BA may adjust this transaction every hour (or less than one hour in some areas) based on their system economics. The section is too restrictive and should allow for other entities to issue market adjusts where appropriate.

Clarification is required for the statement "If denied by any Approval Entity, the original request remains valid". Is this meant to imply that any other hours of the request are still in effect and the denial would only apply to the hour in question?

RFI Standard 10.0 Each PSE submitting a RFI for an Interchange Transaction shall have, or arrange to have, personnel on site and immediately available 24 x 7 for notification of Interchange Transaction changes.

RFI Standard 10.1 These personnel shall be available from the beginning of the Market Period until the end of the Implementation Period.

RFI Standard 11.0 Energy accounting for all RFIs shall be accomplished via Implemented Interchange Block Accounting.

ISO NE:
Make sure this is flexible enough to handle 15 and 30 minutes interchange scheduling changes, the markets are pushing the industry to get off the old one hour block loading and look for 15 and/or 30 minute block loading.

RFI Standard 12.0 Settlement of losses shall be either handled as financial or as payment in-kind.

RFI Standard 12.1 For losses handled as payment in-kind, the PSE shall communicate to the IA the mw losses and the entity the losses are with for each TSP along the transaction path.

ISO NE:
Is the "communication" regarding losses in-kind to be handled through a separate RFI with each in-kind area ?

RFI Standard 12.2 All bilateral transactions are equal and opposite in direction for a source and sink BA.

RFI Standard 13.0 Ramp rates shall be standard across the North American Interconnections.

ISO NE:
At a high level regarding this section, ramp rate is a function of the responsiveness of the BA's system, some units just don't move as fast as others plus the interaction of generators with loads where large MW delta's can occur as load comes in or goes out, sounds more like a reliability standard that NERC should develop for the BA's not NASEB.

Regarding the details in this section, is it really a ramp standard or merely the default ramp rate ? In principle we have allowed entities to go to "off nominal"

ramp rates when mutually agreeable. Standards 13.1 and 13.2 are the current defaults but the way the section reads there is no flexibility to deviate.

Also the industry has traditionally referred to the ramp as a straddle ramp, i.e., 10 minutes over the start time. There is no mention of that in this section.

RFI Standard 13.1 Ramp rate for the Eastern Interconnection shall be 10 minutes equally across the start and end times of the Transaction unless otherwise agreed to by all parties involved in the Transaction.

RFI Standard 13.2 Ramp rate for the Western Interconnection shall be 20 minutes equally across the start and end times of the Transaction unless otherwise agreed to by all parties involved in the Transaction.

RFI Standard 14.0 For Dynamic Transfer Transactions, the requirements shall be established by NERC.

RFI Standard 14.1 Until such time as NERC establishes formal standards for Dynamic Schedule, requirements shall be governed by the most recent version of NERC's "Dynamic Transfer White Paper" shall be followed.

ISO NE:
This section may need language regarding Pseudo ties as well.

3/31/04

p. 0 of 2.

To: NAESB Office
(Wholesale Electric Quadrant)
(713) 356-0067 (F)

From: John Hormozi
Los Angeles Dept. of Water & Power
(818) 771-6606 (F)
(818) 771-6775 (O)

RE: "Coordinate Interchange Business Practices"
(Std. Request # R03013)

Comment: RFI Standard 7.0, as submitted, requires the IA to communicate RFI status changes to, among others, Generator PSEs, Load-Serving PSEs, and PSEs holding the associated transmission rights.
It is my understanding that, in this instance, the proposed standa does not accurately reflect WECC Business Practices in implementation of NERC Policy 3.
Typical transaction chains in the Western Interconnection include numerous PSEs that do not fall into the above categories. These PSEs, who are parties to "static" transactions, need updated RFI status information to support after-the-fact business checkouts and account reconciliation
Attached is an excerpt from the proposed standard, marked in order to reflect the current (and probable future) "e-tagging" practice within the Western Interconnection.
In case of questions, please feel free to contact me at the phone number above, or at john.hormozi@ladwp.com.

W/Thanks, J. Hormozi

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RFI Standard 4.0 A completed RFI shall contain, at a minimum, the required information specified in the most current version of the **NAESB RFI Datasheet** (attached).

RFI Standard 5.0 On behalf of the Requesting PSE, the IA shall verify approvals from all involved Approval Entities (e.g. TSP-for transmission reservations, BA-for ramping start/end times and rate, RA-reliability analysis, Generator/Load PSE) prior to being confirmed and implemented in accordance with the NERC Coordinate Interchange Standard.

RFI Standard 5.1 The Requesting PSE shall submit required RFI information and data in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetable** (attached).

RFI Standard 5.2 Until such time as other protocols are established by NERC and/or NAESB, timing requirements for the submission and approval of the completed RFI shall be in accordance with NERC Policy 3 Appendix 3A1.

RFI Standard 6.0 All requests for approval/validation of the completed RFI by the IA during the Arranged Interchange Period shall be assessed in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetable.** The results of that assessment shall be promptly communicated by the IA back to all involved parties.

RFI Standard 6.1 Any denial of a RFI request by any Approval Entity shall be communicated to the IA and Requesting PSE and accompanied by the reason for such denial.

RFI Standard 7.0 The IA shall be responsible for communicating changes on the status of the RFI to all involved parties of the RFI, including BAs, IAs, RAs, counterparty PSE (Generator or Load Serving), and the TSPs, and the PSEs holding the associated transmission rights necessary to support the transaction. In the Western Interconnection, this shall include all PSEs named in the RFI.

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.

-----Original Message-----
From: Rodriquez, Andrew J.
Sent: Friday, April 16, 2004 12:54 PM
To: 'Simonelli, John'; 'Dison, Joel'; Carter, Roman; vthomason@naesb.org; weqess@naesb.org; Oncken, Todd
Cc: rmcquade@naesb.org; Robert Schwermann; Ed Davis; Andy Rodriguez
Subject: RE: Revised CIBP Standard

Throwing my two cents in....

I would go one step further than John. As a compromise document, I can see that a lot has been done here, and I don't mean to imply that is is not good work or work wasted. But I nonetheless of question if the right things have been done.

As I have suggested before, I would greatly prefer to see two documents:

1.) Business Practice Standards for Interchange Scheduling, and
2.) Business Practice Standards for the E-Tag System

Number 1 should contain implementation neutral things, like "we'll use block accounting," and "schedules must be balanced before flowing."

Number 2 should contain all the things about timing and data requirements, approvals, delivery, etc...

The reason I am saying this is that there is a LOT of stuff in the CIBP document that is not about coordinating interchange; it's about using tagging. Coordinate Interchange standards should apply regardless of whether you are using E-Tag, faxes, or smoke signals. I agree that we need to codify E-Tag rules - but they are NOT the same as Interchange rules, and we should not blur that line by calling them the same thing.

As I articulated in the last meeting, I would prefer we spend more time working this out in detail. I think there are a lot of areas we could improve on. Several of the comments we have seen here (John , Joel, mine) all seem to indicate that there are some legitimate concerns. Can I live with the standard as it is written now? Probably. But do I think it is the right thing to do? Unfortunately, no.

I would personally prefer seeing us come together again and try to get this right. There is a way we can do this that will be robust and extensible... we just need to agree to it.

Andy Rodriquez
PJM Interconnection, L.L.C.

-----Original Message-----
From: Simonelli, John
Sent: Friday, April 16, 2004 11:51 AM
To: 'Dison, Joel'; Carter, Roman; vthomason@naesb.org; weqess@naesb.org; Oncken, Todd
Cc: rmcquade@naesb.org; Robert Schwermann; Ed Davis; Andy Rodriguez
Subject: RE: Revised CIBP Standard

I have concerns as well because the standard, specifically this section does not necessarily match the diagram.

A PSE wishing to construct the deal must submit the "unbalanced" request to the "Market Assembly" (actually I'm really starting to like the term Interchange Coordinator, please indulge me). The Interchange Coordinator (IC) is responsible for reconciling discrepancies and obtaining necessary approvals from the markets side of the house; GEN, GPE, LSE, MO, TSP, etc. Once the IC has a balanced schedule that all market parties agree too, the IC sends the RFI to the IA. The IA per the NERC standard, contacts the affected reliability entities; RA, BA, TSP to obtain final confirmation of the transaction. If all the lights are green, it goes to the BA for implementation. I am not sure the standard adequately conveys this sequence of events.

Based on this interpretation and recognizing the need to expedite the confirmation process, I have no problems with the submission of the RFI by the IC to the IA going to the affected reliability entities; RA, BA, TSP, but it should not go to ALL involved parties.

John

-----Original Message-----
From: Dison, Joel
Sent: Friday, April 16, 2004 10:39
To: Carter, Roman; vthomason@naesb.org; weqess@naesb.org; Oncken, Todd
Cc: rmcquade@naesb.org; Robert Schwermann; Ed Davis; Simonelli, John; Andy Rodriguez
Subject: Revised CIBP Standard

Dear ESS:

Although I am exceedingly appreciative of the CIBPTF's efforts in resolving industry concerns with this standard, I would like to express my personal concerns over the newly revised document (the one posted yesterday) and inform the group that I will probably vote ***AGAINST*** adoption of the standard as written. This version was changed to address an implementation concern expressed by Entergy. The change is in Standard 5.0. However, in my opinion, the change creates a fatal flaw in the standard that I cannot support. As written, Standard 5.0 says:

The completed RFI shall be submitted to the IA and concurrently to all involved parties in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetables** (attached).

It is my opinion that the phrase "concurrently" specifies a given implementation that will (1) unduly restrain the ongoing development of OASIS II, (2) represents a fundamental change to Policy 3, and (3) creates a situation in which the existing ETAG specification and implementation would be in violation of the standard. Entergy's concern is over the situation in which, because of the timing of RFI submissions to the various reliability entities, the IA receives an approval for an RFI that it has not yet seen. This is a legitimate implementation concern that has already been addressed by ETAG and will most certainly be addressed by any other implementation such as OASIS II. If passed as written, however, ETAG would be in violation of this standard because the tag is first sent to the tag authority (which serves as the equivalent of both the market assembly function and the IA) which then sends it to all reliability approval entities - all happening in accordance with the timing tables. It has been expressed that certain language in other parts of the standard "forgive" this violation because they specify transitional use of the ETAG specification document. I disagree for this piece of the standard. Standard 4.1 says that the Tag Authority can serve as the Market Assembly function; Standard 7.1 says that the Tag Authority can serve as the communication vehicle for status changes; and Standard 8.3 says that the "most current" version of the ETAG specification document shall be used as the protocol for submitting the RFI to the IA. None of these forgive the

requirement in Standard 5.0 to send to reliability authorities concurrently to sending to the IA and therefore passage of this standard would require a change to the ETAG specification document. In addition, the language as written will force the OASIS II development team to either (a) limit its scope of possible designs or (b) initiate a change to this standard anyway. It is my opinion that, since the ETAG specification document already handles the implementation concerns expressed by Entergy, there is no reason to force this change. As such, I suggest the original wording that did not specify concurrently:

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

By copy of this email to Veronica and Todd, I want to be certain that this discussion is captures and documented. Thanks.

To the ESS, please give consideration to this discussion prior to the conference call. Thanks.

Joel Dison Manager, Market Policy
Southern Company Generation and Energy Marketing

-----Original Message-----
From: Carter, Roman
Sent: Thursday, April 15, 2004 11:50 AM
To: Veronica@Naesb (vthomason@naesb.org)
Cc: Rae McQuade (rmcquade@naesb.org); Robert Schwermann; Ed Davis; Dison, Joel; Simonelli, John; Andy Rodriguez
Subject:

Veronica, I have made a slight change to the CIBP Standard currently posted on the website for the ESS Conference Call scheduled for tomorrow. Would you please replace the **CIBP Standard.doc** with the attached **CIBP Standard revised.doc**.

Thanks for your help....

Roman Carter
Southern Company Generation
& Energy Marketing

Feedback on NAESB Recommendation R03013 (Coordinate Interchange Business Practice)

Introduction

We interpret the last sentence to mean that this document is concerned with the financial side of the transaction and not the physical side which is covered by the NERC Standards. TVA would like to know if this is a correct assumption.

Definitions

RFI Standard 1.14 TVA would like to see the word “Reliability” changed to “Assessment”. This would be more appropriate especially if our above assumption is correct and this document only addresses the front end of the transaction and not the physical side.

Business Practices

RFI Standard 8.0 TVA would like to see the last word in this sentence changed to NERC.

RFI Standard 8.1 This requirement could be a significant burden to a small utility so TVA would like to see the word “shall” changed to “should”. We would also like to have the phrase” Electronic System” defined.

NAESB RFI Datasheet

It appears that this document is taken right out of NERC Appendix 3A4 except that section B titled Curtailments and Reloads (Reliability Related Profile modifications) has been excluded. We don’t disagree with leaving it out, but would like an explanation for clarification purposes.

Comments on Coordinate Interchange Business Practices by We Energies:

The standard accurately represents Business Practices inherent in NERC Policy 3.

Barb Kedrowski
Project Manager
We Energies

ESS Comments Incorporating Changes into the Recommendation that are Reflective of the Comments

April 16, 2004

To: WEQ Executive Committee

From: Electronic Scheduling Subcommittee

Subject: Coordinate Interchange Business Practice Standard Recommendation

Dear EC Members:

Please accept the following comments regarding the Coordinate Interchange Business Practice Standard Recommendation:

The ESS has thoroughly reviewed and discussed the public comments resulting from the CIBP Standard Recommendation posted for comment in March. Both the comments received and the discussion that ensued as a result of those comments have been extremely productive. After having this discussion, the ESS believes that certain changes to the proposed standard would improve upon its effectiveness and its universal acceptance. As a result, the ESS would like to ask the Executive Committee to consider the attached "new" recommendation as a wholesale replacement for the recommendation that was posted for comment in March. When that standard recommendation is brought before you for passage in May, the ESS would request the dismissal of the original recommendation and consideration of this one in its place. Furthermore, the ESS encourages the Executive Committee to vote in favor of this new recommendation and thereby send it to the NAESB membership for ratification. The ESS appreciates your considerations in this matter and is always available to assist the EC as necessary.

Sincerely

John Simoneli
Andy Rodriquez
Joel Dison
(ESS Chairs for the ESS)

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Revised by the WEQ ESS on April 16, 2004

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

1. RECOMMENDED ACTION:

_X_ Accept as requested
___ Accept as modified below
___ Decline

EFFECT OF EC VOTE TO ACCEPT RECOMMENDED ACTION:
_X_ Change to Existing Practice
___ Status Quo

2. TYPE OF DEVELOPMENT/MAINTENANCE

Per Request:	**Per Recommendation:**
_X_ Initiation	_X_ Initiation
___ Modification	___ Modification
___ Interpretation	___ Interpretation
___ Withdrawal	___ Withdrawal
___ Principle	___ Principle
___ Definition	___ Definition
_X_ Business Practice Standard	_X_ Business Practice Standard
___ Document	___ Document
___ Data Element	___ Data Element
___ Code Value	___ Code Value
___ X12 Implementation Guide	___ X12 Implementation Guide
___ Business Process Documentation	___ Business Process Documentation

3. RECOMMENDATION

SUMMARY:

Accept as requested Business Practices that are consistent with the current version of NERC Policy 3, will complement NERC compliance templates associated with Policy 3, and will ultimately facilitate the implementation of the NERC Coordinate Interchange Reliability Standard currently under development as part of the NERC Standards process.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Revised by the WEQ ESS on April 16, 2004

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RECOMMENDED STANDARDS:

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.

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.**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 completed RFI shall be submitted to the IA and to all involved parties 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.**

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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.

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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.

See also Attachments:

- NAESB RFI Datasheet
- NAESB RFI Submission and Response Timetable

4. SUPPORTING DOCUMENTATION

a. Description of Request:

Request submitted by the NAESB Members of the Joint Interface Committee requesting complementary business practice standards to support NERC's Coordinate Interchange Business Practices Standard.

b. Description of Recommendation:

WEQ Standards Review Subcommittee

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
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On 7/10/03, the WEQ Standards Review Subcommittee established the Coordinate Interchange Business Practices Task Force, which is charged with scoping issues and developing standards pursuant to Request No. R03013 to support the Coordinate Interchange Standards being developed by NERC.

WEQ Coordinate Interchange Business Practices Task Force

On 7/29/03, the CIBPTF began its scoping work by looking at both the work of NERC's Coordinate Interchange Standard Drafting Team and current NERC Policy 3 to identify areas within the policy that have market implications. The CIBPTF completed a scoping document that was sent out for industry comment on 8/19/03.

NAESB-NERC-IRC Joint Interface Committee

On 9/18/03 the Joint Interface Committee determined through a unanimous motion to forward Request R03013 to NAESB for development.

WEQ Coordinate Interchange Business Practices Task Force

The review of NERC Policy 3 concluded at the 10/27-28/03 Joint Meeting of the NERC Interchange Subcommittee, NERC Coordinate Interchange Standards Drafting Team, and NAESB CIBPTF.

WEQ Executive Committee

In early January 2004 the WEQ Executive Committee re-assigned the CIBP to report to the WEQ Electronic Scheduling Subcommittee, in recognition of the transition of the task force from scoping to standards drafting.

WEQ Coordinate Interchange Business Practices Task Force

On 12/02/03 a strawman standard was begun, revised on 1/21/04, and further revised on 2/12/04.

WEQ Electronic Scheduling Subcommittee

On 2/17-18/04 the ESS considered the RFI standard and unanimously adopted the following motion:

> The ESS recommends to the EC the passage of the Coordinate Interchange Business Practice Standard as presented by the CIBPTF, and modified in the February 17-18, 2004 ESS meeting. The Recommended standard shall be posted for public comment until April 2, 2004 and considered at the May EC meeting. The ESS will review public comments on this proposed standard at its scheduled April 5-7 meeting and, if necessary, make recommendations to the EC regarding any modifications to the standard arising from that review.

c. Business Purpose:

The Business Practices will provide market participants with procedures for providing any necessary data for the analysis of interchange, as defined by NERC for reliability purposes, including data format and timing of data submittals.

d. Commentary/Rationale of Subcommittee(s)/Task Force(s):

The WEQ Electronic Scheduling Subcommittee found the Request For Interchange (RFI) Standard to be consistent with the current version of NERC Policy 3, will complement NERC compliance templates

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
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associated with Policy 3, and will ultimately facilitate the implementation of the NERC Coordinate Interchange Reliability Standard currently under development as part of the NERC Standards process.The Coordinate Interchange Business Practices Task Force (CIBPTF) and WEQ Electronic Scheduling Subcommittee met on the following days and to prepare the document and recommendation and all work papers may be found on the following web pages (http://naesb.org/weq/weq_cibp.asp and http://naesb.org/weq/weq_electronic_scheduling.asp):

- July 29, 2003 Conference Call CIBPTF
- October 21, 2003 Conference Call CIBPTF
- October 27-28, 2003 Meeting CIBPTF
- December 2, 2003 Meeting CIBPTF
- January 21, 2004 Meeting CIBPTF
- February 17-18, 2004 Meeting ESS

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.

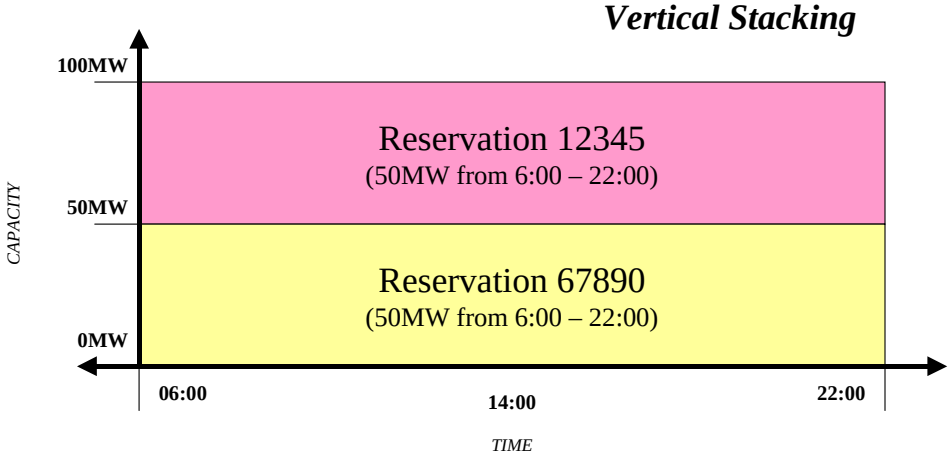
Using Multiple Transmission Reservations to Support a Single Leg of an Interchange

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:

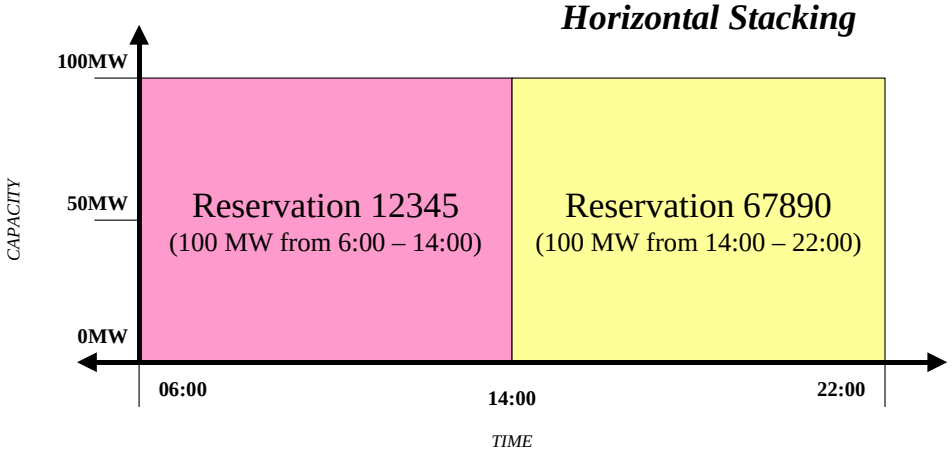
- Vertical stacking, in which a Transmission Customer combines multiple reservations to achieve a certain net level of transmission capacity, and
- Horizontal stacking, in which a Transmission Customer combines multiple reservations to achieve a certain transmission capacity coverage over time.

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

A. Eastern Interconnection – New Interchanges
B. Western Interconnection – New Interchanges
C. Interchange Corrections
D. 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	Approval Entity response to IA
Less than 24 Hours	20 Minutes prior to start	≤1 Hour prior to start	≤ 10 Minutes from RFI receipt	≥ 10 Min prior to start of interchange
		>1 to <4 hours prior to start	≤20 Minutes from RFI receipt	≥ 40 Min prior to start of interchange
		≥ 4 Hours prior to start	≤ 2 Hours from RFI receipt	≥ 2 Hours prior to start of interchange
24 Hours or longer	4 Hours prior to start	Any	≤ 2 Hours from RFI receipt	≥ 2 Hours prior to start of interchange
*Start time references are for start of the INTERCHANGE not the start of the ramp. + Includes BA, RA, TSP, IA				

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	Approval Entity response to IA
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 prior to start of interchange**

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 prior to start of interchange**
		<4 Hours to ≥1 Hour prior to start	**20 minutes from RFI receipt**	**Passive Approval Deferred denial**	**≥ 40 Min prior to start of interchange**
		<1 hour to ≥30 minutes prior to start	**10 minutes from RFI receipt**	**Passive Approval Deferred denial**	**≥ 20 Min prior to start of interchange**
		<30 minutes to ≥20 minutes prior to start	**10 minutes from RFI receipt**	**Passive Approval Deferred denial**	**≥ 10 Min prior to start of interchange**
	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, IA

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 20 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

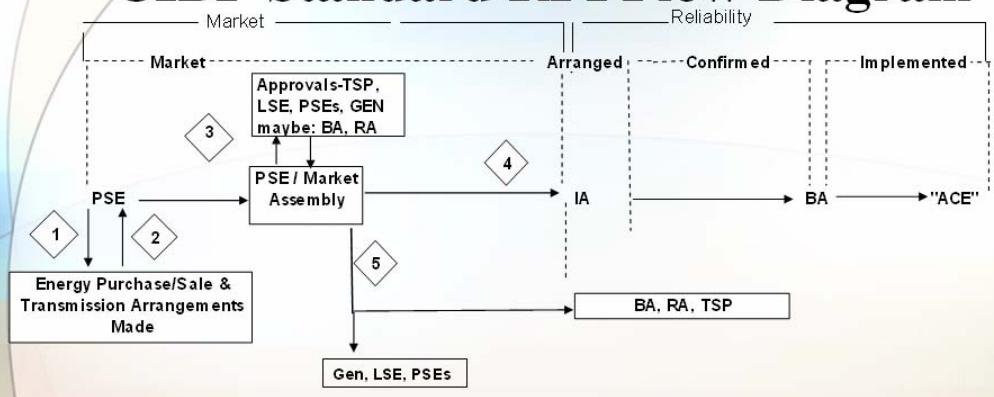
Special Exception for Cancellations

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 requested/received by PSE/Market Assembly Function.
- **4** - Submission of RFI by PSE/Market Assembly Function to IA. RFI includes reliability data (required) and business information.
- **5** - PSE/Market Assembly Function sends RFI request to market and reliability Approval Entities.

TAB 10

Transition Issues

- ***Letter from NERC***
- ***Transition Plan for Level 0 NERC Reliability Standards Development***
- ***NERC SAR***

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

April 21, 2004

Mr. Michael Deselle
Director–Public Policy
American Electric Power
1616 Woodall Rodgers Freeway
Dallas, Texas, 75202-1234

Ms Rae McQuade
Executive Director
North American Energy Standards Board
1301 Fannin Street
Suite 2350
Houston, Texas 77002

Dear Michael and Rae,

Accelerated Transition to "Version 0" Reliability Standards

The NERC Standards Transition Management Team (STMT) and the Standards Authorization Committee (SAC) today approved the attached "Plan for Accelerating the Adoption of NERC Reliability Standards". The STMT and SAC are encouraged by the strong support this project is receiving throughout the industry.

The goal of the project is to translate the existing NERC reliability rules, comprised of operating policies, planning standards, and compliance templates, into an integrated set of reliability standards, and to be positioned in February 2005 to move forward with one set of NERC standards administered through the ANSI-accredited process. Specific objectives are to:

1. Translate the existing reliability rules — namely the existing board-approved operating policies and planning standards, the 38 compliance templates approved by the NERC board on April 2, and all approved revisions to Operating Policies 5, 6, and 9 being balloted in April 2004 — into an initial baseline (Version 0) set of reliability standards for adoption by the NERC board at its February 8, 2005 meeting.
2. Identify the Functional Model designation for each performance requirement and measure in the Version 0 standards and determine, in concert with objective 3, whether to adopt the Functional Model designations into the Version 0 standards.
3. Complete an initial registration (not certification) of all functions identified in Version 0 standards by October 31, 2004.
4. *In cooperation with NAESB and the ISO/RTO Council (IRC), and with the endorsement of the Joint Interface Committee (JIC), identify sections of the existing operating policies and planning standards that are suitable for NAESB to incorporate into their equivalent "Version 0" business practice standards.*

5. Retire existing NERC operating policies, planning standards, and compliance templates coincident with adoption of the Version 0 standards. Material that is not part of Version 0 standards will be made into NERC reference documents or NAESB business practices, or dropped if not needed.

Objective 4 above underscores the importance of our two organizations working closely together to identify sections of the existing NERC operating policies and planning standards that are suitable for NAESB to incorporate into business practice standards. We look forward to that effort, which will by necessity be taking place on multiple fronts. Consistent with the Market Committee board-approved scope, I am requesting the Market Committee to ensure NERC's interactions with NAESB and the IRC necessary to support the standards transition project are well-coordinated.

You may feel free to distribute the NERC standards transition plan within the NAESB community.

Please contact me if you have any questions at 609-452-8060 or Gerry.Cauley@nerc.net.

Sincerely,

Gerry Cauley

Gerry Cauley
Director–Standards

GWC:naw

cc: Michael S. Grim, Market Committee Chairman
Standards Authorization Committee
Standards Transition Management Team

Plan for Accelerating the Adoption of NERC Reliability Standards

FINAL
April 19, 2004

Standards Transition Management Team

Standards Authorization Committee

Standards Transition Overview

This document describes a plan for accelerating the transition from existing NERC operating policies, planning standards and compliance templates to an integrated set of reliability standards by February 2005. The goal is to develop a "Version 0" baseline set of standards translated from the existing requirements and measures provided in:

- The April 2, 2004 Board-approved compliance templates.
- The existing operating policies, including modifications to Operating Policies 5, 6, and 9 made to address lessons learned from the August 14, 2003, blackout.
- The existing planning standards.

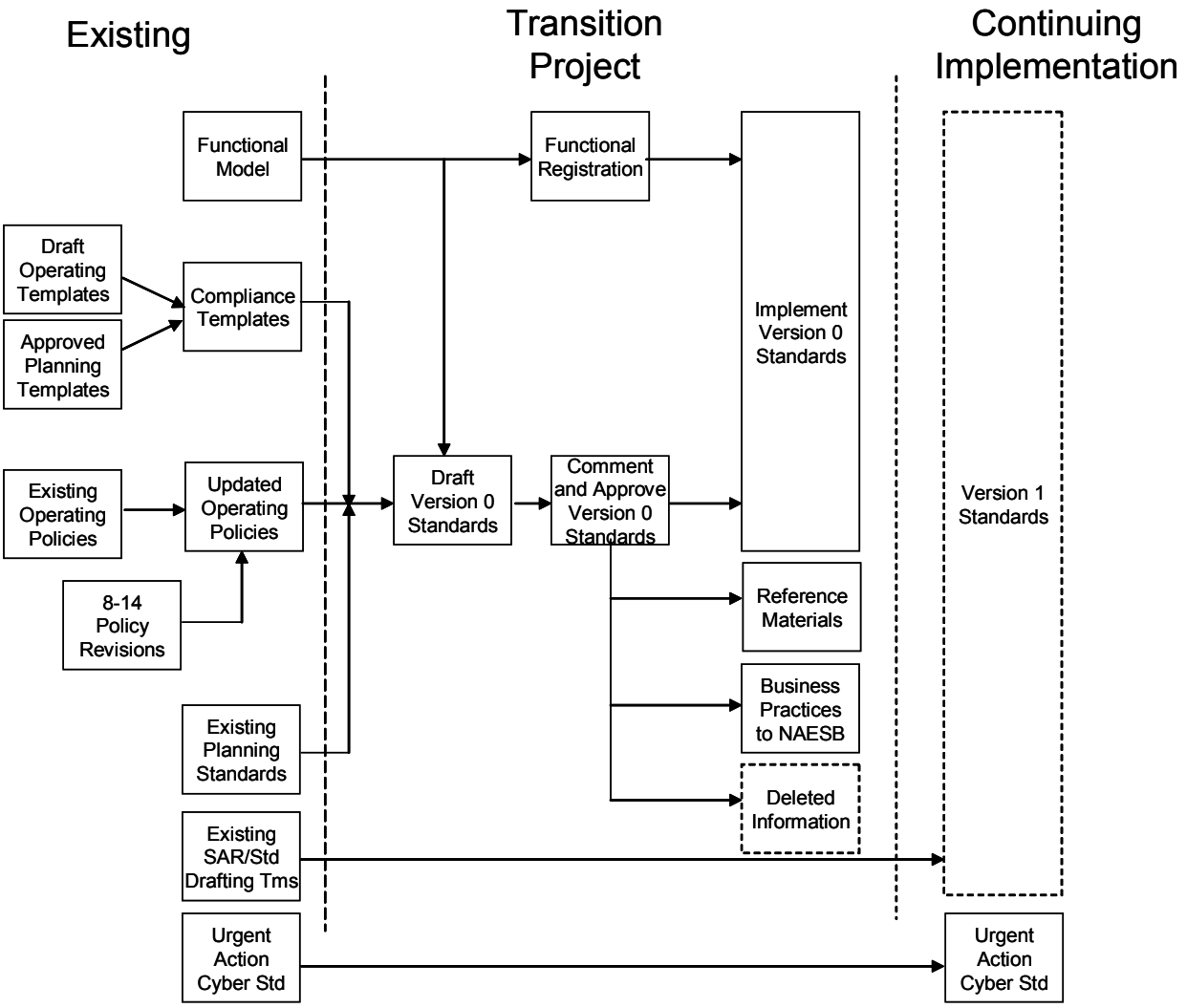


Figure 1 – Standards Transition Overview

In the drafting of the Version 0 standards, the Functional Model will be applied to designate functions to which each existing requirement and measure applies. In parallel, NERC and the

Regional Councils will seek to register all entities that perform the functions identified in the Version 0 standards.

The goal is to develop the Version 0 standards using the existing NERC Standards Process Manual. In the translation, portions of the existing reliability documents may be designated as Version 0 standards, potential business practice standards, reference materials, or may be subject to deletion.

Previously defined Standards Authorization Requests (SARs) and draft standards are expected to continue on their paths to adoption as Version 1 reliability standards, adding to or replacing the appropriate Version 0 standards subsequent to adoption of the Version 0 standards. The Urgent Action Cyber Security Standard (1200) is already a standard and is unaffected by the transition project.

A list of acronyms used in this plan is provided below for ease of reference.

ANSI	American National Standards Institute
BPRT	Business Practice Review Team
CCC	Compliance and Certification Committee
CCMC	Compliance and Certification Managers Committee
CIPC	Critical Infrastructure Protection Committee
DT	Drafting team
FERC	Federal Energy Regulatory Commission (FERC)
IRC	ISO/RTO Council
JIC	Joint Interface Committee
MC	Market Committee
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Council
OC	Operating Committee
PC	Planning Committee
SAC	Standards Authorization Committee
SAR	Standard Authorization Request
SPM	Standards Process Manual
STMT	Standards Transition Management Team
ST	Support Team

Background

In June 2002, the NERC Board of Trustees approved a new, consensus-based standards development procedure founded on the American National Standards Institute (ANSI) principles of openness, inclusiveness, balance, and fairness. On this basis, ANSI certified NERC as an ANSI standards developer in March 2003. NERC adopted the ANSI-based standards procedure primarily in response to a transformation of the industry that saw the reliability responsibilities of a finite set of vertically integrated utilities become unbundled to a more diverse spectrum of entities forming the market-based wholesale electric industry. The open standards process allows all parties responsible for, or impacted by, bulk electric system reliability to participate in the standards process.

The development of new reliability standards was initially conceived to start from a "clean slate", rather than translating existing NERC operating policies and planning standards. A clean slate approach was preferred because it allowed better organization of the standards and necessitated establishing a logical reliability basis for proposing a standard rather than assuming continuation of 'the way it has always been done'. There are currently 16 reliability standards in some stage of development: eleven originally proposed standards covering a minimum set of requirements for reliable planning and operation of bulk electric systems; four additional standards addressing certification criteria for reliability service providers; and a standard on cyber security adopted in August 2003 as an urgent action. Despite the progress to date, the development of reliability standards in the new process has been slower than initially expected.

Pending adoption of a minimum set of reliability standards, the NERC Operating Committee (OC) has continued to maintain its nine operating policies and associated appendices through the use of a transitional procedure. NERC also has 48 planning standards and 91 associated measures that were developed by the Planning Committee (PC). The concept until now for transitioning from existing operating policies and planning standards to new standards has been to adopt each new standard individually and retire appropriate sections of the existing documents, although a detailed plan was never developed and no standards have been transitioned in this manner.

The Functional Model was adopted by the NERC board initially in June 2001 and was revised in February 2004. The Functional Model provides a flexible framework for developing reliability standards in an unbundled industry in which the control area operated by a vertically integrated utility is no longer the sole entity responsible for reliability. Although the Functional Model has gained widespread acceptance conceptually, it has not yet seen significant application by NERC or the industry.

Need for Accelerating the Standards Transition

There are several important reasons for accelerating the transition from existing operating policies and planning standards to a single set of reliability standards under the ANSI-accredited process:

1. The August 14 blackout has challenged NERC and the industry to demonstrate that its reliability standards are unambiguous and measurable – now.

2. The U.S./Canada Power System Outage Task Force final report of April 5, 2004 states in Recommendation 25: "NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards."
3. An April 14, 2004 order of the Federal Energy Regulatory Commission (FERC) states a policy objective addressing "the need to expeditiously modify [NERC] reliability standards in order to make these standards clear and enforceable."
4. The continued use of multiple formats, processes and forums for developing and maintaining reliability rules is an inefficient dilution of industry and staff resources.
5. The transition to new standards and retiring of existing operating policies and planning standards will be too complex for industry implementation if taken one standard at a time over several years.

The August 14, 2003 blackout has created an urgent need for NERC to ensure that its reliability standards are clear and measurable. This need has been reinforced by Recommendation 25 of the U.S./Canada Power System Outage Task Force and FERC's reliability policy objective, as noted above.

As an immediate step, the NERC board on April 2, 2004 adopted a set of 38 compliance templates to augment the existing operating policies and planning standards by clarifying some requirements and adding measures to be used in compliance audits. While not covering the complete set of operating policies and planning standards, the compliance templates address the most significant reliability issues to be reviewed during compliance evaluations. Additionally, the OC has proposed revisions to Operating Policies 5, 6 and 9 to clarify the responsibilities and authorities of control areas and reliability coordinators.

With the adoption of the compliance templates in April 2004, NERC now has four different sets of reliability documents: operating policies, planning standards, compliance templates, and emerging new reliability standards. Maintaining these documents creates an unnecessary burden on the industry of working in multiple forums and is an inefficient dilution of resources. In most cases, there has been a concerted effort to maintain a separation between standard drafting teams in the new process and the technical committees, resulting in multiple groups working on related topics. These demands are in addition to the need for the industry to participate in the development of business practice standards by the North American Energy Standards Board (NAESB).

The process for transferring to a new reliability standard and concurrently retiring applicable sections of the operating policies and planning standards was always recognized to be complex, particularly for the entities who must follow the reliability rules and the Regional Councils who are implementing the compliance programs. A protracted, multi-year transition would be confusing and more difficult than a more abbreviated effort to replace the operating policies and planning standards in a single step.

Objectives of the Accelerated Standards Transition

The goal of the accelerated standards transition project is to translate the existing NERC reliability rules, comprised of operating policies, planning standards, and compliance templates,

into an integrated set of reliability standards, and to be positioned in February 2005 to move forward with one set of NERC standards administered through the ANSI-accredited process.

Specific objectives are to:

1. Translate the existing reliability rules – namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the NERC board on April 2, and all approved revisions to Operating Policies 5, 6, and 9 being balloted in April 2004 – into an initial baseline (Version 0) set of reliability standards for adoption by the NERC Board at its February 8, 2005 meeting.
2. Identify the Functional Model designation for each performance requirement and measure in the Version 0 standards and determine, in concert with objective 3, whether to adopt the Functional Model designations into the Version 0 standards.
3. Complete an initial registration (not certification) of all functions identified in Version 0 standards by October 31, 2004.
4. In cooperation with NAESB and the ISO/RTO Council (IRC), and with the endorsement of the Joint Interface Committee (JIC) identify sections of the existing operating policies and planning standards that are suitable for NAESB to incorporate into their equivalent "Version 0" business practice standards.
5. Retire existing NERC operating policies, planning standards and compliance templates coincident with adoption of the Version 0 standards. Material that is not part of Version 0 standards will be made into NERC reference documents or NAESB business practices, or dropped if not needed.
6. Coordinate Version 0 standards development with the Compliance and Certification Committee (CCC) and Compliance and Certification Managers Committee (CCMC), to assist them in developing the compliance monitoring program for 2005 and beyond.
7. Support the continuing development of Version 1 reliability standards already in progress to become additions to or replacements of applicable sections of Version 0. Any new standards would be implemented subsequent to the adoption of Version 0.
8. Be prepared beginning in 2005 to consolidate the use of technical resources working in similar content areas (e.g. technical committees and drafting teams) to make more efficient use of resources in developing and revising standards.
9. Evaluate and improve the standards process so that it is responsive to reliability needs, while complying with the ANSI essential requirements.

Guiding Principles

The following principles are essential to the success of this project:

1. To expedite consensus, the scope of the Version 0 standards will incorporate the existing reliability rules in effect in April 2004 – namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the Board on April 2, and approved revisions to Operating Policies 5, 6, and 9 that are being balloted in April 2004. The Standards Authorization Committee (SAC) and the Standards Transition Management Team (STMT) strongly urge that previous transitional processes not be used to

further modify the existing operating policies, planning standards, and compliance templates during the translation to Version 0 standards.

2. In the drafting of Version 0 standards, when differences are identified in the language used in an existing operating policy or planning standard compared to that of a corresponding Board-approved compliance template, the more explicit statements of requirements and measures, generally contained in the compliance templates, will be adopted. For existing operating policy requirements that have no corresponding compliance template, the measures will be shown as "Not Specified", rather than proposing new measures. Board-approved compliance templates for which there is no corresponding operating policy requirement or planning standard shall nonetheless be included as part of the Version 0 standards.
3. NERC will utilize the existing ANSI-accredited standards process for the development and adoption of the Version 0 standards. To expedite the transition, the Standards Authorization Committee (SAC) will manage some steps in parallel and manage the number of comment periods.
4. The Version 0 standards will be developed with due consideration of the impacts on existing NERC and Regional Council compliance monitoring programs.
5. NERC will work closely with NAESB, the IRC, the Regional Councils and the industry to achieve the stated objectives.
6. To facilitate consensus, a detailed mapping will be provided to show how the existing reliability documents translate into Version 0 standards, reference documents, and business practices. Therefore, each interim draft will retain information on the changes made, such as designation of new functions or identification of reference material or business practices.
7. A successful project depends on building consensus. Several checkpoints have been included in the project timeline to assess consensus.
8. All stakeholders are strongly encouraged to provide inputs early in the transition, especially during the public comment periods for the SAR and draft Version 0 standards. Because of the complexity of the project, no additional revisions will be permitted once the Version 0 standards are posted for committee and ballot pool approval.

Project Management

The NERC Director of Standards will serve as project director.

The STMT, comprised of the Vice Chairperson of each of the NERC committees, serves as the project requestor by sponsoring the SAR for the Version 0 standards and has associated decision authorities as outlined in the detailed schedule below. The STMT also ensures that the standards transition activities of the various committees are coordinated. Each committee retains its existing authorities and responsibilities as related to this project.

The SAC manages the ANSI-accredited standards development process for the development and approval of the Version 0 standards. Specific responsibilities are outlined in the detailed project schedule. Additionally, the SAC retains all of its responsibilities and authorities identified in the Standards Process Manual. The STMT and SAC must work closely together, with the SAC managing the standards process and the STMT coordinating work efforts and actions among the various committees.

In accordance with the Standards Process Manual, the SAC will appoint a Version 0 drafting team with due consideration of expertise and balance. To expedite the work effort, it is expected the drafting team may form subgroups, such as operating and planning, to work on portions of the Version 0 standards. A small support team, comprised of several staff members and consultants, will be assigned to assist the drafting team in developing their work.

Major Milestone Deliverables

The major milestone deliverables are as follows:

Date	Milestone
4/19/04	Transition plan approved for publication.
4/19/04	SAR on Version 0 standards posted for comment until May 17.
4/19/04	Solicit nominations for Version 0 drafting team and self-selection for ballot pool.
5/7/04	Version 0 drafting team formed.
5/28/04	Consideration of comments on the SAR posted. Evaluation of consensus based on comments received and support for project.
6/4/04	Inputs to Version 0 standards received from technical subcommittees.
7/2/04	First draft of Version 0 standards posted for standing committee agendas and public comment.
8/30/04	Second draft Version 0 standards posted for public comment until October 15, 2004
10/15/04	Initial registration of applicable reliability functions completed.
10/25/04	Third draft Version 0 standards posted to standing committees for endorsement at November 8-12 meetings.
10/25/04	Third draft Version 0 standards posted to ballot pool for 30-day pre-ballot period.
11/12/04	Standing committees endorse Version 0 standards.
12/10/04	Initial ballot of Version 0 standards complete.
1/7/05	Second ballot of Version 0 standards complete (assuming a recirculation ballot is required).
1/10/05	Final draft Version 0 standards posted for Board adoption.
2/8/05	Board adoption of Version 0 standards.

Implementation Schedule

The schedule below provides a work plan to achieve the stated objectives. The dates shown are expected completion dates – many tasks must begin well before the specified dates.

Date	Task	Assigned To
4/14/04	Approve SAR for Version 0 standards and appoint STMT as SAR drafting team for the purpose of considering comments.	SAC
4/14/04	Approve Version 0 standard drafting team nomination form.	SAC
4/19/04	Approve transition plan.	STMT/SAC
4/19/04	Post and announce: • Transition plan. • SAR (through 5/17/04). • Request for nominations to Version 0 standard drafting team (through 4/30/04). • Self-selection for Version 0 ballot pool.	NERC Staff
4/19/04	Assign technical subcommittees to provide inputs to Version 0 standards, as appropriate.	OC/PC/MC
4/19/04	Assign 3-4 person dedicated Support Team (ST), comprised of staff and contractors, to begin initial work and assist drafting team.	NERC Staff
4/19/04	Inform MC and NAESB of need to form a business practice review team (BPRT) to coordinate assimilation of business practices.	NERC Staff
4/19/04	Inform Organization Certification Working Group and Regional Councils of objectives and timeline for initial functional registration by October 15, 2004.	NERC Staff
4/19/04	Inform CCC and CCMC of objectives and timeline for evaluating impacts on the 2005 compliance program and preparing the 2005 compliance plan.	NERC Staff
4/21-22/04	OC subcommittees meet and work on inputs to Version 0	OC
4/30/04	Close nominations for Version 0 standard drafting team.	NERC Staff
4/30/04	Approve posting of Standards Process Manual (SPM) revision to allow SAC to make administrative and procedural revisions to the manual.	SAC
5/7/04	Approve Version 0 standard drafting team.	SAC
5/14/04	Initial mapping of compliance templates into Version 0 format. Significant progress in mapping planning standards into Version 0 format.	ST

5/17/04	Close Version 0 SAR comment period.	NERC Staff
5/17/04	Post revision to SPM for comment through June 17.	SPM DT
5/18/04	Review SAR and project plans with JIC for informational purposes.	SAC/JIC
5/20-21/04	Initial meeting of Version 0 drafting team (DT).	DT/ST
5/28/04	Prepare and post consideration of comments on SAR. Evaluate and report to SAC on consensus.	STMT
5/28/04	Finalize Version 0 communications plan.	SAC
5/28/04	Assess consensus based on SAR comments and approve drafting of Version 0 standards.	SAC
6/4/04	Provide inputs to draft Version 0 standards.	OC/PC/MC
6/4/04	Forward OC/PC/MC subcommittee recommendations on business practices to BPRT.	NERC Staff
6/9-11/04	Version 0 drafting team second meeting.	DT/ST
6/9/04	Version 0 drafting team finalizes general organization and numbering scheme for Version 0 standards.	DT/ST
6/15/04	Approve transition project.	Board
6/28-30	Drafting team third meeting to finalize draft 1 of Version 0 standards.	DT/ST
7/2/04	Post first draft of Version 0 standards for standing committee agendas and public comment. Key unresolved issues highlighted.	NERC Staff
7/20-26	Standing committee review of first draft Version 0.	OC/PC/MC/CIPC
7/30/04	Close comment period on first draft of Version 0 standard.	NERC Staff
8/9-10/04	SAC meeting.	SAC
8/11-13/04	Drafting team meeting to prepare second draft and response to comments.	DT/ST
8/30/04	Post second draft Version 0 standards for public comment until 10/15/04.	DT/ST
8/30/04	Complete ballot of revision to SPM to allow SAC revisions to administrative procedures.	SPM DT
10/4/04	Proposed revisions to streamline SPM steps posted for 30-day comment period.	
10/15/04	Complete initial registration of applicable reliability functions.	OCTF/Reliability Councils
10/15/04	Close comment period on draft 2.	NERC Staff
10/22/04	Prepare consideration of comments on draft 2 and prepare draft 3 of Version 0 for posting to standing committees for	DT/ST

	endorsement at November 9-11 meetings.	
10/25/04	Evaluate consensus and determine whether to ballot Version 0 standards.	SAC
10/25/04	Post draft 3 Version 0 standards to ballot pool for 30-day pre-ballot period.	NERC Staff
11/8-12/04	Standing committees endorse Version 0 standards by committee action.	OC/PC/MC/CIPC
11/11-12/04	SAC meeting. Assess consensus on Version 0 going to ballot and proposed revisions to streamline the Standards Process Manual.	SAC
12/10/04	Complete first ballot of Version 0 standards.	Ballot Pool
12/15/04	Complete consideration of comments submitted with negative ballots, if needed.	SPM/Drafting Team
1/7/05	Complete recirculation ballot of Version 0 standards, if needed.	Ballot Pool
1/10/05	Post final draft Version 0 standards for Board adoption February 8, 2005	NERC Staff
1/12/05	SCEC and SAC executives joint meeting to coordinate use of technical resources in development of standards.	SCEC/SAC
2/8/05	Board considers adoption of Version 0 standards.	BOT

Standards Authorization Request

When completed, email to: gerry.cauley@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Version 0 Reliability Standards
Request Date	4/16/04

SAR Requestor Information		**SAR Type** (Put an 'x' in front of one of these selections)	
Name	Standards Transition Management Team	☒	New Standard
Primary Contact	Gerry Cauley	☐	Revision to existing Standard
Telephone	609-452-8060	☐	Withdrawal of existing Standard
Fax	609-452-9550		
E-mail	gerry.cauley@nerc.net	☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

There are several important reasons for accelerating the transition from existing operating policies and planning standards to a single set of reliability standards under the ANSI-accredited process:

1. The August 14 blackout has challenged NERC and the industry to demonstrate that its reliability standards are unambiguous and measurable – now.

2. The U.S./Canada Power System Outage Task Force final report of April 5, 2004 states in Recommendation 25: "NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards."

3. An April 14, 2004 order of the Federal Energy Regulatory Commission (FERC) states a policy objective addressing "the need to expeditiously modify [NERC] reliability standards in order to make these standards clear and enforceable."

4. The continued use of multiple formats, processes and forums for developing and maintaining reliability rules is an inefficient dilution of industry and staff resources.

5. The transition to new standards and retiring of existing operating policies and planning standards will be too complex for industry implementation if taken one standard at a time over several years.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies by double clicking the grey boxes.)*		
☒	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☒	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☒	Planning Authority	Plans the bulk electric system
☒	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
☒	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☒	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☒	Transmission Owner	Owns transmission facilities
☒	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☒	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☒	Generator Owner	Owns and maintains generation unit(s)
☒	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☒	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☒	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☒	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

The applicable functions will be identified in translation of existing operating policies, planning standards, and compliance templates into Version 0 standards. Although, all functions are checked above, some functions may not have performance requirements in the existing reliability rules.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check boxes for all that apply by double clicking the grey boxes.)*	
☒	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☒	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)*	
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes	
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

1. Translate the existing reliability rules – namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the NERC board on April 2, and all approved revisions to Operating Policies 5, 6, and 9 being balloted in April 2004 – into an initial baseline (Version 0) set of reliability standards.

2. Identify the Functional Model designation for each performance requirement and measure in the Version 0 standards.

3. Identify sections of the existing operating policies and planning standards that are suitable for NAESB to incorporate into their equivalent "Version 0" business practice standards.

4. Retire existing NERC operating policies, planning standards and compliance templates coincident with adoption of the Version 0 standards. Material that is not part of Version 0 standards will be made into NERC reference documents or NAESB business practices, or dropped if not needed.

A more detailed implementation plan is provided in the attached "Plan for Accelerating the Adoption of NERC Reliability Standards".

Related Standards

Standard No.	Explanation
1200	Urgent Action Cyber Security Standard is unaffected by this project, since it is already an approved standard.
	All other standards and SARS in development will continue as planned, except the implementation plan must be revised to consider what portions of Version 0 standards must be retired upon adoption of a Version 1 standard.

Related SARs

SAR ID	Explanation
	Same as above.

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	Explanation
	The development of Version 0 standards is intended to retire all existing operating policies, planning standards, and compliance templates.

Plan for Accelerating the Adoption of NERC Reliability Standards

FINAL
April 19, 2004

Standards Transition Management Team

Standards Authorization Committee

Standards Transition Overview

This document describes a plan for accelerating the transition from existing NERC operating policies, planning standards and compliance templates to an integrated set of reliability standards by February 2005. The goal is to develop a "Version 0" baseline set of standards translated from the existing requirements and measures provided in:

- The April 2, 2004 Board-approved compliance templates.
- The existing operating policies, including modifications to Operating Policies 5, 6, and 9 made to address lessons learned from the August 14, 2003, blackout.
- The existing planning standards.

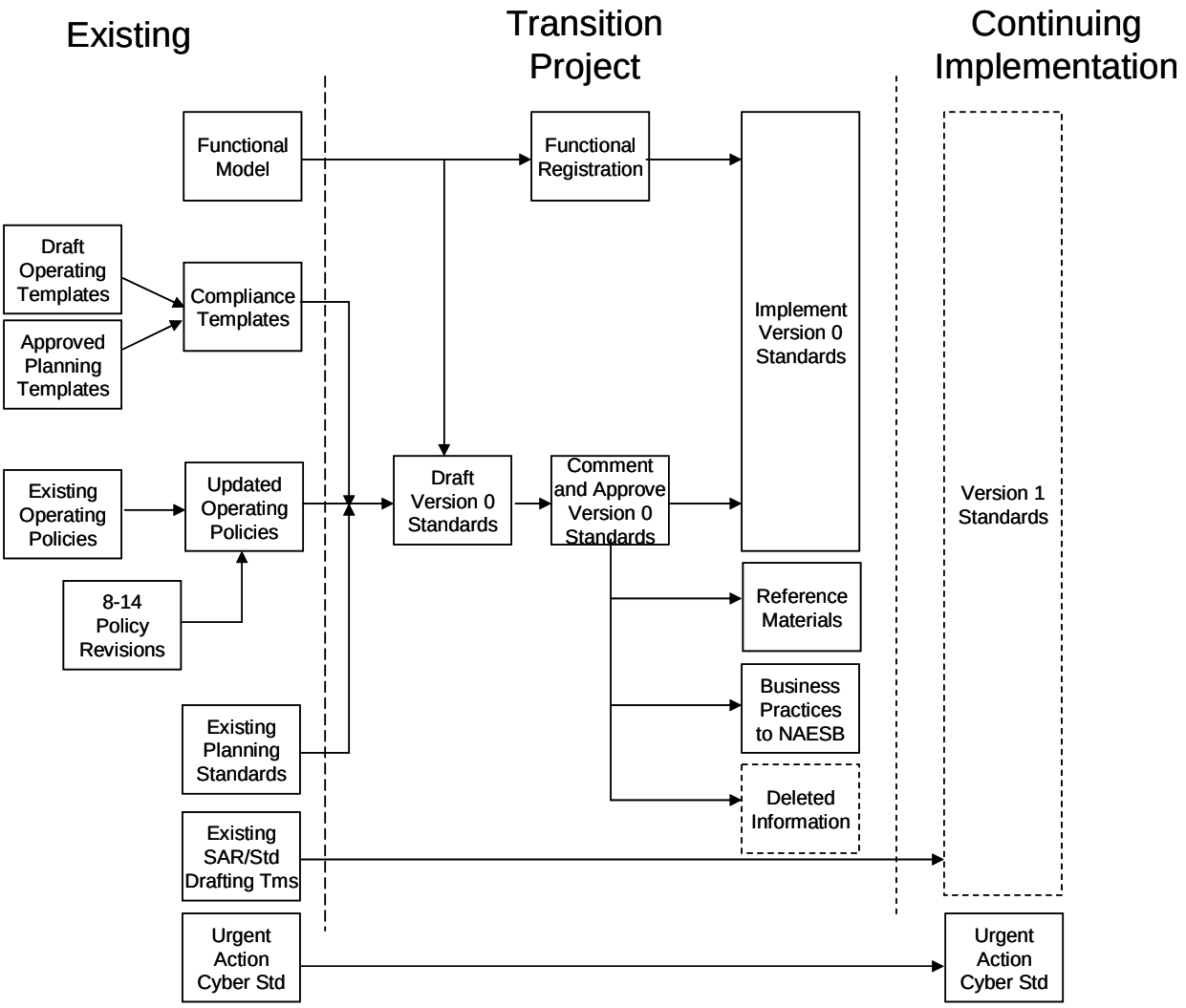


Figure 1 – Standards Transition Overview

In the drafting of the Version 0 standards, the Functional Model will be applied to designate functions to which each existing requirement and measure applies. In parallel, NERC and the

Regional Councils will seek to register all entities that perform the functions identified in the Version 0 standards.

The goal is to develop the Version 0 standards using the existing NERC Standards Process Manual. In the translation, portions of the existing reliability documents may be designated as Version 0 standards, potential business practice standards, reference materials, or may be subject to deletion.

Previously defined Standards Authorization Requests (SARs) and draft standards are expected to continue on their paths to adoption as Version 1 reliability standards, adding to or replacing the appropriate Version 0 standards subsequent to adoption of the Version 0 standards. The Urgent Action Cyber Security Standard (1200) is already a standard and is unaffected by the transition project.

A list of acronyms used in this plan is provided below for ease of reference.

ANSI	American National Standards Institute
BPRT	Business Practice Review Team
CCC	Compliance and Certification Committee
CCMC	Compliance and Certification Managers Committee
CIPC	Critical Infrastructure Protection Committee
DT	Drafting team
FERC	Federal Energy Regulatory Commission (FERC)
IRC	ISO/RTO Council
JIC	Joint Interface Committee
MC	Market Committee
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Council
OC	Operating Committee
PC	Planning Committee
SAC	Standards Authorization Committee
SAR	Standard Authorization Request
SPM	Standards Process Manual
STMT	Standards Transition Management Team
ST	Support Team

Background

In June 2002, the NERC Board of Trustees approved a new, consensus-based standards development procedure founded on the American National Standards Institute (ANSI) principles of openness, inclusiveness, balance, and fairness. On this basis, ANSI certified NERC as an ANSI standards developer in March 2003. NERC adopted the ANSI-based standards procedure primarily in response to a transformation of the industry that saw the reliability responsibilities of a finite set of vertically integrated utilities become unbundled to a more diverse spectrum of entities forming the market-based wholesale electric industry. The open standards process allows all parties responsible for, or impacted by, bulk electric system reliability to participate in the standards process.

The development of new reliability standards was initially conceived to start from a "clean slate", rather than translating existing NERC operating policies and planning standards. A clean slate approach was preferred because it allowed better organization of the standards and necessitated establishing a logical reliability basis for proposing a standard rather than assuming continuation of 'the way it has always been done'. There are currently 16 reliability standards in some stage of development: eleven originally proposed standards covering a minimum set of requirements for reliable planning and operation of bulk electric systems; four additional standards addressing certification criteria for reliability service providers; and a standard on cyber security adopted in August 2003 as an urgent action. Despite the progress to date, the development of reliability standards in the new process has been slower than initially expected.

Pending adoption of a minimum set of reliability standards, the NERC Operating Committee (OC) has continued to maintain its nine operating policies and associated appendices through the use of a transitional procedure. NERC also has 48 planning standards and 91 associated measures that were developed by the Planning Committee (PC). The concept until now for transitioning from existing operating policies and planning standards to new standards has been to adopt each new standard individually and retire appropriate sections of the existing documents, although a detailed plan was never developed and no standards have been transitioned in this manner.

The Functional Model was adopted by the NERC board initially in June 2001 and was revised in February 2004. The Functional Model provides a flexible framework for developing reliability standards in an unbundled industry in which the control area operated by a vertically integrated utility is no longer the sole entity responsible for reliability. Although the Functional Model has gained widespread acceptance conceptually, it has not yet seen significant application by NERC or the industry.

Need for Accelerating the Standards Transition

There are several important reasons for accelerating the transition from existing operating policies and planning standards to a single set of reliability standards under the ANSI-accredited process:

1. The August 14 blackout has challenged NERC and the industry to demonstrate that its reliability standards are unambiguous and measurable – now.

2. The U.S./Canada Power System Outage Task Force final report of April 5, 2004 states in Recommendation 25: "NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards."
3. An April 14, 2004 order of the Federal Energy Regulatory Commission (FERC) states a policy objective addressing "the need to expeditiously modify [NERC] reliability standards in order to make these standards clear and enforceable."
4. The continued use of multiple formats, processes and forums for developing and maintaining reliability rules is an inefficient dilution of industry and staff resources.
5. The transition to new standards and retiring of existing operating policies and planning standards will be too complex for industry implementation if taken one standard at a time over several years.

The August 14, 2003 blackout has created an urgent need for NERC to ensure that its reliability standards are clear and measurable. This need has been reinforced by Recommendation 25 of the U.S./Canada Power System Outage Task Force and FERC's reliability policy objective, as noted above.

As an immediate step, the NERC board on April 2, 2004 adopted a set of 38 compliance templates to augment the existing operating policies and planning standards by clarifying some requirements and adding measures to be used in compliance audits. While not covering the complete set of operating policies and planning standards, the compliance templates address the most significant reliability issues to be reviewed during compliance evaluations. Additionally, the OC has proposed revisions to Operating Policies 5, 6 and 9 to clarify the responsibilities and authorities of control areas and reliability coordinators.

With the adoption of the compliance templates in April 2004, NERC now has four different sets of reliability documents: operating policies, planning standards, compliance templates, and emerging new reliability standards. Maintaining these documents creates an unnecessary burden on the industry of working in multiple forums and is an inefficient dilution of resources. In most cases, there has been a concerted effort to maintain a separation between standard drafting teams in the new process and the technical committees, resulting in multiple groups working on related topics. These demands are in addition to the need for the industry to participate in the development of business practice standards by the North American Energy Standards Board (NAESB).

The process for transferring to a new reliability standard and concurrently retiring applicable sections of the operating policies and planning standards was always recognized to be complex, particularly for the entities who must follow the reliability rules and the Regional Councils who are implementing the compliance programs. A protracted, multi-year transition would be confusing and more difficult than a more abbreviated effort to replace the operating policies and planning standards in a single step.

Objectives of the Accelerated Standards Transition

The goal of the accelerated standards transition project is to translate the existing NERC reliability rules, comprised of operating policies, planning standards, and compliance templates,

into an integrated set of reliability standards, and to be positioned in February 2005 to move forward with one set of NERC standards administered through the ANSI-accredited process.

Specific objectives are to:

1. Translate the existing reliability rules – namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the NERC board on April 2, and all approved revisions to Operating Policies 5, 6, and 9 being balloted in April 2004 – into an initial baseline (Version 0) set of reliability standards for adoption by the NERC Board at its February 8, 2005 meeting.
2. Identify the Functional Model designation for each performance requirement and measure in the Version 0 standards and determine, in concert with objective 3, whether to adopt the Functional Model designations into the Version 0 standards.
3. Complete an initial registration (not certification) of all functions identified in Version 0 standards by October 31, 2004.
4. In cooperation with NAESB and the ISO/RTO Council (IRC), and with the endorsement of the Joint Interface Committee (JIC) identify sections of the existing operating policies and planning standards that are suitable for NAESB to incorporate into their equivalent "Version 0" business practice standards.
5. Retire existing NERC operating policies, planning standards and compliance templates coincident with adoption of the Version 0 standards. Material that is not part of Version 0 standards will be made into NERC reference documents or NAESB business practices, or dropped if not needed.
6. Coordinate Version 0 standards development with the Compliance and Certification Committee (CCC) and Compliance and Certification Managers Committee (CCMC), to assist them in developing the compliance monitoring program for 2005 and beyond.
7. Support the continuing development of Version 1 reliability standards already in progress to become additions to or replacements of applicable sections of Version 0. Any new standards would be implemented subsequent to the adoption of Version 0.
8. Be prepared beginning in 2005 to consolidate the use of technical resources working in similar content areas (e.g. technical committees and drafting teams) to make more efficient use of resources in developing and revising standards.
9. Evaluate and improve the standards process so that it is responsive to reliability needs, while complying with the ANSI essential requirements.

Guiding Principles

The following principles are essential to the success of this project:

1. To expedite consensus, the scope of the Version 0 standards will incorporate the existing reliability rules in effect in April 2004 – namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the Board on April 2, and approved revisions to Operating Policies 5, 6, and 9 that are being balloted in April 2004. The Standards Authorization Committee (SAC) and the Standards Transition Management Team (STMT) strongly urge that previous transitional processes not be used to

further modify the existing operating policies, planning standards, and compliance templates during the translation to Version 0 standards.

2. In the drafting of Version 0 standards, when differences are identified in the language used in an existing operating policy or planning standard compared to that of a corresponding Board-approved compliance template, the more explicit statements of requirements and measures, generally contained in the compliance templates, will be adopted. For existing operating policy requirements that have no corresponding compliance template, the measures will be shown as "Not Specified", rather than proposing new measures. Board-approved compliance templates for which there is no corresponding operating policy requirement or planning standard shall nonetheless be included as part of the Version 0 standards.
3. NERC will utilize the existing ANSI-accredited standards process for the development and adoption of the Version 0 standards. To expedite the transition, the Standards Authorization Committee (SAC) will manage some steps in parallel and manage the number of comment periods.
4. The Version 0 standards will be developed with due consideration of the impacts on existing NERC and Regional Council compliance monitoring programs.
5. NERC will work closely with NAESB, the IRC, the Regional Councils and the industry to achieve the stated objectives.
6. To facilitate consensus, a detailed mapping will be provided to show how the existing reliability documents translate into Version 0 standards, reference documents, and business practices. Therefore, each interim draft will retain information on the changes made, such as designation of new functions or identification of reference material or business practices.
7. A successful project depends on building consensus. Several checkpoints have been included in the project timeline to assess consensus.
8. All stakeholders are strongly encouraged to provide inputs early in the transition, especially during the public comment periods for the SAR and draft Version 0 standards. Because of the complexity of the project, no additional revisions will be permitted once the Version 0 standards are posted for committee and ballot pool approval.

Project Management

The NERC Director of Standards will serve as project director.

The STMT, comprised of the Vice Chairperson of each of the NERC committees, serves as the project requestor by sponsoring the SAR for the Version 0 standards and has associated decision authorities as outlined in the detailed schedule below. The STMT also ensures that the standards transition activities of the various committees are coordinated. Each committee retains its existing authorities and responsibilities as related to this project.

The SAC manages the ANSI-accredited standards development process for the development and approval of the Version 0 standards. Specific responsibilities are outlined in the detailed project schedule. Additionally, the SAC retains all of its responsibilities and authorities identified in the Standards Process Manual. The STMT and SAC must work closely together, with the SAC managing the standards process and the STMT coordinating work efforts and actions among the various committees.

In accordance with the Standards Process Manual, the SAC will appoint a Version 0 drafting team with due consideration of expertise and balance. To expedite the work effort, it is expected the drafting team may form subgroups, such as operating and planning, to work on portions of the Version 0 standards. A small support team, comprised of several staff members and consultants, will be assigned to assist the drafting team in developing their work.

Major Milestone Deliverables

The major milestone deliverables are as follows:

Date	Milestone
4/19/04	Transition plan approved for publication.
4/19/04	SAR on Version 0 standards posted for comment until May 17.
4/19/04	Solicit nominations for Version 0 drafting team and self-selection for ballot pool.
5/7/04	Version 0 drafting team formed.
5/28/04	Consideration of comments on the SAR posted. Evaluation of consensus based on comments received and support for project.
6/4/04	Inputs to Version 0 standards received from technical subcommittees.
7/2/04	First draft of Version 0 standards posted for standing committee agendas and public comment.
8/30/04	Second draft Version 0 standards posted for public comment until October 15, 2004
10/15/04	Initial registration of applicable reliability functions completed.
10/25/04	Third draft Version 0 standards posted to standing committees for endorsement at November 8-12 meetings.
10/25/04	Third draft Version 0 standards posted to ballot pool for 30-day pre-ballot period.
11/12/04	Standing committees endorse Version 0 standards.
12/10/04	Initial ballot of Version 0 standards complete.
1/7/05	Second ballot of Version 0 standards complete (assuming a recirculation ballot is required).
1/10/05	Final draft Version 0 standards posted for Board adoption.
2/8/05	Board adoption of Version 0 standards.

Implementation Schedule

The schedule below provides a work plan to achieve the stated objectives. The dates shown are expected completion dates – many tasks must begin well before the specified dates.

Date	Task	Assigned To
4/14/04	Approve SAR for Version 0 standards and appoint STMT as SAR drafting team for the purpose of considering comments.	SAC
4/14/04	Approve Version 0 standard drafting team nomination form.	SAC
4/19/04	Approve transition plan.	STMT/SAC
4/19/04	Post and announce: • Transition plan. • SAR (through 5/17/04). • Request for nominations to Version 0 standard drafting team (through 4/30/04). • Self-selection for Version 0 ballot pool.	NERC Staff
4/19/04	Assign technical subcommittees to provide inputs to Version 0 standards, as appropriate.	OC/PC/MC
4/19/04	Assign 3-4 person dedicated Support Team (ST), comprised of staff and contractors, to begin initial work and assist drafting team.	NERC Staff
4/19/04	Inform MC and NAESB of need to form a business practice review team (BPRT) to coordinate assimilation of business practices.	NERC Staff
4/19/04	Inform Organization Certification Working Group and Regional Councils of objectives and timeline for initial functional registration by October 15, 2004.	NERC Staff
4/19/04	Inform CCC and CCMC of objectives and timeline for evaluating impacts on the 2005 compliance program and preparing the 2005 compliance plan.	NERC Staff
4/21-22/04	OC subcommittees meet and work on inputs to Version 0	OC
4/30/04	Close nominations for Version 0 standard drafting team.	NERC Staff
4/30/04	Approve posting of Standards Process Manual (SPM) revision to allow SAC to make administrative and procedural revisions to the manual.	SAC
5/7/04	Approve Version 0 standard drafting team.	SAC
5/14/04	Initial mapping of compliance templates into Version 0 format. Significant progress in mapping planning standards into Version 0 format.	ST

5/17/04	Close Version 0 SAR comment period.	NERC Staff
5/17/04	Post revision to SPM for comment through June 17.	SPM DT
5/18/04	Review SAR and project plans with JIC for informational purposes.	SAC/JIC
5/20-21/04	Initial meeting of Version 0 drafting team (DT).	DT/ST
5/28/04	Prepare and post consideration of comments on SAR. Evaluate and report to SAC on consensus.	STMT
5/28/04	Finalize Version 0 communications plan.	SAC
5/28/04	Assess consensus based on SAR comments and approve drafting of Version 0 standards.	SAC
6/4/04	Provide inputs to draft Version 0 standards.	OC/PC/MC
6/4/04	Forward OC/PC/MC subcommittee recommendations on business practices to BPRT.	NERC Staff
6/9-11/04	Version 0 drafting team second meeting.	DT/ST
6/9/04	Version 0 drafting team finalizes general organization and numbering scheme for Version 0 standards.	DT/ST
6/15/04	Approve transition project.	Board
6/28-30	Drafting team third meeting to finalize draft 1 of Version 0 standards.	DT/ST
7/2/04	Post first draft of Version 0 standards for standing committee agendas and public comment. Key unresolved issues highlighted.	NERC Staff
7/20-26	Standing committee review of first draft Version 0.	OC/PC/MC/CIPC
7/30/04	Close comment period on first draft of Version 0 standard.	NERC Staff
8/9-10/04	SAC meeting.	SAC
8/11-13/04	Drafting team meeting to prepare second draft and response to comments.	DT/ST
8/30/04	Post second draft Version 0 standards for public comment until 10/15/04.	DT/ST
8/30/04	Complete ballot of revision to SPM to allow SAC revisions to administrative procedures.	SPM DT
10/4/04	Proposed revisions to streamline SPM steps posted for 30-day comment period.	
10/15/04	Complete initial registration of applicable reliability functions.	OCTF/Reliability Councils
10/15/04	Close comment period on draft 2.	NERC Staff
10/22/04	Prepare consideration of comments on draft 2 and prepare draft 3 of Version 0 for posting to standing committees for	DT/ST

	endorsement at November 9-11 meetings.	
10/25/04	Evaluate consensus and determine whether to ballot Version 0 standards.	SAC
10/25/04	Post draft 3 Version 0 standards to ballot pool for 30-day pre-ballot period.	NERC Staff
11/8-12/04	Standing committees endorse Version 0 standards by committee action.	OC/PC/MC/CIPC
11/11-12/04	SAC meeting. Assess consensus on Version 0 going to ballot and proposed revisions to streamline the Standards Process Manual.	SAC
12/10/04	Complete first ballot of Version 0 standards.	Ballot Pool
12/15/04	Complete consideration of comments submitted with negative ballots, if needed.	SPM/Drafting Team
1/7/05	Complete recirculation ballot of Version 0 standards, if needed.	Ballot Pool
1/10/05	Post final draft Version 0 standards for Board adoption February 8, 2005	NERC Staff
1/12/05	SCEC and SAC executives joint meeting to coordinate use of technical resources in development of standards.	SCEC/SAC
2/8/05	Board considers adoption of Version 0 standards.	BOT

TAB 11

Membership Structure

Attachment A

NAESB WHOLESALE ELECTRIC QUADRANT
PROPOSED INITIAL QUADRANT PROCEDURES
JULY 10, 2002

The NAESB Wholesale Electric Quadrant will be composed of five segments. Each segment will have six seats on the Board of Directors and the Executive Committee. The organization for the segments is shown below:

- **Transmission:** Any entity engaged in the activity of owning, operating or controlling bulk electric transmission facilities in North America.

Sub-segments:	Muni/Coop	Number of Seats:	1
	Fed/State/Provincial		1
	IOU		2
	ITC		2

- **Generation:** Any entity engaged in the activity of owning and/or operating wholesale electric generation facilities in North America.

Sub-segments:	Muni/Coop	Number of Seats:	1
	Fed/State/Provincial		1
	IOU		2
	Merchant		2

- **Marketers/Brokers:** Any entity engaged in the activity of buying and selling wholesale electric power in North America on a physical or financial basis.

Sub-segments:	Muni/Coop	Number of Seats:	1
	Fed/State/provincial		1
	Not IOU affiliated		2
	IOU Affiliated		2

- **Distribution/Load Serving Entities:** Any entity engaged in the activity of electric power sales and/or delivery to end use customers in North America, or any entity designated to represent a distribution utility.

Sub-segments:	Muni/Coop	Number of Seats:	2
	IOU		2
	Competitive Retailer		1
	(not available to muni/coop, IOU or IOU affiliates)		
	Other		1
	(not available to muni/coop, IOU or IOU affiliates)		

- **End Users:** Any entity in North America that is an end use consumer of electricity, engages in electricity regulation, or represents customer interests, or any entity designated to represent an end user.

Sub-segments:	End Use (also in another segment)	Number of Seats:	1
	Regulator		1
	Residential/Commercial		1
	Large Industrial (not in other segments)		2
	End Use (Self Generation)		1

IOU Definition: An investor owned entity who has substantial business interest in owning and/or operating any two of the following three asset categories --- generation, transmission, distribution.

Attachment A (cont.)

Procedural Elements:

1. Entities may participate in multiple segments within WEQ.

2. "Sunrise ." Sub-segment principles will continue. Sub-segments may be revisited at any time, but no later than three years. Changes to sub-segments require 75% affirmative from with segment, subject to other minimum participation and deadline requirements.

3. RTO/ISO/IMO participation. All RTOs/ISOs and comparable Canadian entities are strongly encouraged to participate in the Standards drafting process from conception through drafting to the ratification stage. Furthermore, a Technical Advisory Council comprising those jurisdictionally-approved entities will be formed to provide technical support and counsel to the NAESB Board and EC. The Council will have the obligation to provide a technical assessment, evaluation and recommendation to the EC on all Standards relevant to the grid system and RTO market operations. Furthermore, the Council has an affirmative obligation to apprise the EC of a given Standard's feasibility.

4. Fixed Annual Payment. All WEQ participants will pay a fixed annual payment. Annual payment should provide for required budget to administer the process to develop Standards. Exceptions must be approved by the NAESB Board.

5. Sub-segment population. NAESB WEQ will establish minimum number for populating sub-segments within a segment, including a deadline for such population.

6. Consultants. Contract consultants may be considered as an option for Standards drafting, contingent on identification of need and availability of sufficient funding.

Final comprehensive affirmation. This vote *[the vote taken by the Wholesale Electric Quadrant Formation Group on July 10 to endorse this package for forwarding to the NAESB Board of Directors for approval]* will reflect only the elements of this settlement. No changes of any kind can be made to this agreement without prior agreement of parties