



NERC-NAESB-ISO/RTO Council Joint Interface Committee

June 15, 2006 (2–4:30 p.m. EDT)

Dial-In Information

Telephone: 732-694-2061
Pass Code June 15: 11470615
Facilitator: Bill Blevins

Meeting Agenda

1. Administrative Items

- a. Introductions
- b. Roster and Membership Changes
- c. Establish Quorum
- d. Antitrust Guidelines
- e. Prior Meeting Minutes
- f. Agenda

2. Proposed Reliability Standards

- a. Approve the NERC standards development of Relay Loadability
- b. Approve the NERC standards development of Violation Risk Factors
- c. Approve the NERC standards development of IRO-004 Revisions for timely data submission
- d. Approve the NERC standards development of Assess Transmission Future Needs and Develop Transmission Plans

3. Proposed Business Practice Standards

- a. Approve the NAESB Business Practice development of R5020 Guidance for rounding of partial mWhs revision to WEQBPS-002-000
- b. Approve the NAESB Business Practice development of R6006 Market Operator Adjustment
- c. Approve the NAESB Business Practice development of R05019

4. NERC-NAESB Procedure for Joint Standards Development and Coordination

- a. Board Action on NERC-NAESB Procedure for Joint Standards Development and Coordination (Informational purposes)
- b. Update on ATC/TTC/AFC-CBM/TRM NERC Drafting Team and R05004 NAESB joint standards development (Informational purposes)
- c. Update on IRO-006 General Update Coordination with NAESB to separate the Reliability Elements and the Business Practice Elements (Informational purposes)

5. Other Business

- a. Status of Functional Model and Regional Reliability Plans (Informational purposes)
- b. Future Meetings and Conference Calls
- c. Other Business

Adjourn

Joint Interface Committee (NERC-NAESB-IRC)

Co-Chair	Linda Campbell Director of Reliability	Florida Reliability Coordinating Council 1408 N. Westshore Boulevard Suite 1002 Tampa, Florida 33607-4512	(813) 289-5644 (813) 289-5646 Fx lcampbell@ frcc.com
Co-Chair	Michael Desselle Director - Public Policy	American Electric Power 1201 Elm Street Suite 800 Dallas, Texas 75270	(214) 777-1083 (214) 777-1119 Fx mddesselle@ aep.com
Co-Chairman	Charles H. Yeung Executive Director, Interregional Affairs	Southwest Power Pool 415 North McKinley Suite 140 Little Rock, Arkansas 72205-3020	(832) 724-6142 cyeung@spp.org
Vice President, Operations	Donald M. Benjamin Vice President and Director of Members' Forums	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 (609) 452-9550 Fx don.benjamin@ nerc.net
ISO/RTO	Kenneth W. Laughlin Vice President-Market Services	PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	(610) 935-5904 (610) 666-4762 Fx laughlkw@pjm.com
ISO/RTO	To Be Named		
ISO/RTO	William C. Phillips Vice President, Interregional Coordination and Policy	Midwest ISO, Inc. 701 City Center Drive Carmel, Indiana 46032	(317) 249-5420 (317) 249-5703 Fx wphillips@ midwestiso.org
NAESB Representative	John A. Anderson President and CEO	Electricity Consumers Resource Council 1333 H Street, N.W. 8th Floor, West Tower Washington, D.C. 20005	(202) 682-1390 (202) 289-6370 Fx janderson@ elcon.org
NERC Representative	Mark E. Fidrych Power Operations Specialist	Western Area Power Administration MC J0003 P.O. Box 3700 Loveland, Colorado 80539-3003	(970) 461-7240 (970) 461-7299 Fx fidrych@wapa.gov
NAESB Representative	Barry Green Director, Markets and Research	Ontario Power Generation Inc. 700 University Avenue, H18 G3 Toronto, Ontario M5G 1X6	(416) 592-7883 (416) 592-8519 Fx barry.green@ opg.com
NERC Representative	R. Scott Henry Vice President, Electric Systems Operations	Duke Energy Corp. 526 South Church Street P.O. Box 1006 Charlotte, North Carolina 28201-1006	(704) 382-6182 (704) 382-4671 Fx rshenry@ duke-energy.com

NERC Representative	Sam R. Jones Interim CEO	Electric Reliability Council of Texas, Inc. 2705 West Lake Drive Taylor, Texas 76574-2136	(512) 225-7177 (512) 248-3095 Fx sjones@ercot.com
ISO/RTO	P.S. (Ben) Li President	Ben Li Associates, Inc. 37 Goldring Crescent Markham, Ontario L6C 1Y6	(647) 388-1498 ben.li@iemo.com
NERC Representative	Michael D. Penstone Manager, Standards and Policy	Hydro One Networks, Inc. 483 Bay Street, NT15 Toronto, Ontario M5G 2P5	(416) 345-5444 (416) 345-5422 Fx mike.penstone@hydroone.com
NERC Representative	William F. Reinke President & CEO	SERC Reliability Corporation P.O. Box 70 Cornelius, North Carolina 28031	(704) 875-1726 (704) 875-1087 Fx wreinke@serc1.org
ISO/RTO	H. Kent Saathoff Director of System Operations	Electric Reliability Council of Texas, Inc. 2705 West Lake Drive Taylor, Texas 76574	(512) 248-3011 (512) 248-3095 Fx ksaathoff@ercot.com
NAESB Representative	Robert D. Schwermann Project Manager, System Standards	Sacramento Municipal Utility District 6301 South Street MS A404 Sacramento, California 95817	(916) 732-5519 bschwer@smud.org
NAESB Representative	Kathy York Senior Specialist, Energy Markets and Policy	Tennessee Valley Authority 1101 Market Street MR 2A Chattanooga, Tennessee 37402	(423) 751-3398 (423) 751-7462 Fx keyork@tva.gov
NAESB First Alternate	Syd Berwager Industry Restructuring Project Manager	Bonneville Power Administration P.O. Box 3621 Portland, Oregon 97232	(503) 230-5657 (503) 230-3270 Fx sdberwager@bpa.gov
NAESB Alternate	Edward J. Davis Policy Consultant	Entergy Services, Inc. 1000 Roma Avenue Hammond, Louisiana 70403	(504) 310-5884 edavis@entergy.com
NAESB Second Alternate	Andrew C. Dotterweich Transmission and Regulatory Strategies	Consumers Energy Co. 212 W. Michigan Avenue Jackson, Michigan 49281	(517) 788-0495 acdottweich@cmsenergy.com
NAESB First Alternate	Michael F. Gildea Vice President of Regulatory Affairs	Constellation Generation Group 111 Market Place Suite 200 Baltimore, Maryland 21202	(410) 230-4901 (443) 213-3679 Fx michael.gildea@constellation.com
NAESB Alternate	John P. Hughes Vice President, Technical Affairs	Electricity Consumers Resource Council 1333 H Street, N.W. 8th Floor, West Tower Washington, D.C. 20005	(202) 682-1390 (202) 289-6370 Fx jhughes@elcon.org
NAESB Representative	John Lucas Manager, Transmission Services	Southern Company Services, Inc. 600 North 18th Street PCC Corporate Headquarters Birmingham, Alabama 35291-8210	(205) 257-7200 (205) 257-6663 Fx jelucas@southernco.com

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NAESB Second Alternate	Ron Mucci Senior Vice President, Shared Services	Williams 1 Williams Center MD 34-8 Tulsa, Oklahoma 74102	(918) 573-8728 ron.m.mucci@williams.com
ISO/RTO Alternate	Diana Darlean Pommen Director Business Operations	Alberta Electric System Operator 2500, 300 - 5th Avenue SW Calgary, Alberta T2P 0L4	(403) 539-2510 (403) 539-2949 Fx diana.pommen@aeso.ca
NAESB Second Alternate	Jim R. Templeton Principal	Comprehensive Energy Services, Inc. 2929 Briarpark, Suite 220 Houston, Texas 77042	(713) 759-6999 (713) 781-4966 Fx jrtemplton@aol.com
NAESB Alternate	Roy True	6100 West 96th Street Suite 175 Indianapolis, Indiana 46278	(317) 344-7203 royt@acespower.com
IRC Alternate	Stephen G. Whitley Senior Vice President & Chief Operating Officer	ISO New England, Inc. One Sullivan Road Holyoke, Massachusetts 01040-2841	(413) 535-4361 (413) 535-4050 Fx swhitley@iso-ne.com
NAESB Alternate	Walter L. Yeager Managing Director, Market Development	Cinergy Services Inc. 139 East Fourth Street Cincinnati, Ohio 45202	(513) 419-5711 (513) 419-5511 Fx walt.yeager@cinergy.com
NERC Staff	William D. Blevins Manager of Business Practice Interface	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 bill.blevins@nerc.net
NERC Staff	Gerry W. Cauley Vice President and Director of Standards	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-9550 (609) 452-9550 Fx gerry.cauley@nerc.net



NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

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

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

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

II. PROHIBITED ACTIVITIES

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

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

III. ACTIVITIES THAT ARE PERMITTED

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

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

- Reliability Standards Process Manual
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

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

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

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

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

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

**North American Energy Standards Board**

1301 Fannin, Suite 2350, Houston, Texas 77002

Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: naesb@naesb.orgHome Page: www.naesb.org

January 27, 2006**TO:** NERC-NAESB-ISO/RTO Council Joint Interface Committee, and Interested Industry Participants**FROM:** Laura B. Kennedy, Meeting/Project Manager**RE:** Joint Interface Committee Conference Call Draft Minutes – January 12, 2006

NERC-NAESB-ISO/RTO Council Joint Interface Committee**Conference Call****January 12, 2006 – 2:00 pm to 4:00 pm Central****DRAFT MINUTES****1. Administrative Items**

Mr. Desselle called the meeting to order and welcomed the participants. Mr. Benjamin called the roster of the Joint Interface Committee (JIC) members and a quorum was established. Ms. Kennedy read the antitrust guidelines. Ms. Campbell made a motion to adopt the minutes from the October 5, 2005 meeting as drafted. Mr. Berwager seconded the motion. The motion passed unanimously. The minutes are posted on the NAESB website at: http://www.naesb.org/pdf2/weq_jic100505fm.doc. Mr. Berwager moved, seconded by Ms. Pommen to adopt the agenda. The agenda was unanimously adopted.

2. NERC, NAESB, and IRC Annual PlansNAESB Annual Plan:

Mr. Desselle reviewed the 2006 WEQ Annual Plan approved by the NAESB Board of Directors on December 13, 2005. (The WEQ Annual Plan is included as Item 2a in the Agenda packet). The Annual Plan consists of three general headings for standards development with the specific requests that relate to those general headings listed as sub-items. The three general items are: develop business practices standards as needed to complement reliability standards; develop business practice standards for Version 1 to support ATC calculations; and develop business practices standards to improve the current operation of the wholesale electric market and develop and maintain business practice and communication standards for OASIS and Electronic Scheduling. The Annual Plan also includes eight provisional items.

Mr. Yeung asked the meaning of the First Quarter 2006 date assigned to Request No. R03007 PKI Initiative (e-MARC). Mr. Desselle stated that the NERC/NAESB Joint Interchange Scheduling Working Group (JISWG) has been assigned Request No. R03007. It is the expectation that the JISWG will complete its work on this request by the end of the first quarter this year. Mr. Yeung stated that the IRC is interested in the work on this request. He stated that the IRC was not supportive of NERC's PKI Initiative. Mr. Desselle encouraged representatives of the IRC to participate in the JISWG meetings when this request is discussed.

Mr. Yeung stated that the IRC was concerned with the development of a standard such as e-Marc because a number of different suppliers or vendors of e-Tag that would not be able to meet proposed requirements without a dramatic change to the products already in use by entities. Ms. McQuade stated that the NAESB model business practices drafted to address this request would not likely include requirements that only one vendor could provide.

Mr. Bilke asked what forum Item 1(g) "Develop jointly with NERC a Joint NERC/NAESB Operating training manual" would be developed. Mr. Desselle stated that the NAESB



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Coordination Committee is working with NERC to determine the forum the Joint Operating training manual will be developed as well as addressing other NERC/NAESB coordination issues.

IRC 2006 Annual Work Plan:

Mr. Yeung provided the review of the IRC's 2006 Annual Work Plan. (The IRC 2006 Annual Work Plan is included as Item 2b in the Agenda packet). Mr. Yeung stated that the 2006 Annual Work Plan, like previous plans, is drafted to primarily track the standards development activities of NERC and NAESB. The plan lists the specific NERC reliability standards development that the IRC is tracking and includes placeholders for reliability standards initiatives that are likely to begin in 2006. The IRC plan does not recognize any initiatives regarding the formation of the ERO, but as those activities progress, the IRC will add them to the IRC plan. The plan also lists the specific NAESB business standards development activities that the IRC will track in 2006. A section was added for ITC Initiatives "aimed at improving the ability of ISO/RTO organizations to standardize their methodologies for certain tools used by their respective system operators and IT organizations."

Ms. McQuade asked if the IRC has reevaluated its position on participation and voting in NAESB meetings, since they do track the NAESB standards development, much of which when adopted, will apply to them. Mr. Yeung stated that the CEOs have not indicated a change in the position. He stated that it was up to the individual ISOs and RTOs whether to participate in NAESB meetings and whether to vote in subcommittees and task forces. IRC members are specifically prohibited from joining and voting at the NAESB Executive Committee or Board level.

NERC Standards Authorization Committee 2006 Work Plan:

Ms. Campbell reviewed the NERC Standards Authorization Committee (SAC) 2006 Work Plan. Ms. Campbell stated that the draft of the NERC SAC 2006 Work Plan provided for this meeting is the draft of the plan as of January 11, 2006 and has not been formally approved. The SAC will vote on the plan via an e-mail ballot and the NERC Board is scheduled to vote on the plan during its February meeting.

Ms. Campbell highlighted the 2006 Standards Program Goals and 2006 Standards Program Objectives that begin on page 3 of the Plan. These items have a high priority and the SAC plans to take an active role in the management of these activities.

Mr. Desselle stated that NERC sent a letter to NAESB in December 2004 after the Version 0 efforts were completed but prior to the filing of the status report requesting that the Version 1 standards for ACE Special Cases, Time Error Correction, and Inadvertent Interchange be developed solely by NERC. Mr. Desselle noted that these items were not included in the SAC 2006 Work Plan. Ms. Campbell stated that the SAC has not reviewed SARs on the referenced standards development items. Mr. Benjamin stated that the SAC should receive SARs on those items within the next month. Mr. Desselle stated that once the standards are developed and ratified by NERC, NAESB will consider withdrawing the standards, provided that the withdrawal passes a vote at the Executive Committee and the WEQ members ratify the withdrawal. If the withdrawal is ratified, NAESB will inform the FERC of the withdrawal via a status report.



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3. NERC SAR to revise IRO-006-1, “Transmission Loading Relief” and NAESB Business Practice Request

Mr. Kezele reviewed the NERC SAR to modify IRO-006-1 to allow Market Flow Information as input to IDC. (This document is included as Item 3a in the Agenda packet). Mr. Kezele stated the SAR seeks to modify the NERC TLR procedure to include Market Flows in the scope of values accepted by the Interchange Distribution Calculator. The SAR cites similar regional differences that are currently in place for MISO and PJM. The SAR is currently out for public comment. NERC expects to respond to the comments by March 1 and to post the SAR for ballot on April 1. If the NERC Board approves the SAR on May 1, it would meet SPP’s targeted market start time of May 1, 2006.

Mr. Kezele stated that he worked with NAESB to develop a companion NAESB Request to maintain synchronization with the NAESB TLR business practices. Mr. Desselle stated that the companion NAESB Request was received by NAESB on January 10 and had not been processed through NAESB’s Triage Subcommittee. (The Request was assigned Request No. R06002). Mr. Desselle moved to approve the NERC SAR to revise IRO-006-1 TLR Modifications to NERC for further development and the companion NAESB Request, Request No. R06002, to NAESB assuming the NAESB Triage Subcommittee accepts the request and assigns to the WEQ for development. Ms. Campbell seconded the motion.

Ms. McQuade stated that the motion if adopted would have the JIC making a decision on a NAESB request that has not been processed through the NAESB Triage Subcommittee. She stated that she did not want the action on R06002 to set a precedence of a modification to the NAESB and JIC procedures. Ms. Pommen stated that to address this issue, the JIC members should note that the vote on NAESB Request No. R06002 is not intended nor should it be a precedent for future NAESB Requests. Mr. Henry stated that each organization determines when to bring forth a request or SAR to the JIC. Ms. McQuade stated that NAESB did not formally submit Request No. R06002 to the JIC for assignment at this meeting.

Mr. Phillips asked how a proposed revision was drafted when a SAR drafting team had not been assembled. He stated that Attachment C2 of the SAR included in the JIC agenda packet does make changes to the existing process. MISO representatives have volunteered to be on this standard drafting team, but have not received notice that a drafting team had been assembled. Mr. Desselle suggested that in adoption of the motion, Attachment C2 in the JIC Agenda not be considered a part of the SAR, but a draft for informational purposes only. Mr. Phillips agreed with Mr. Desselle’s suggestion. Mr. Phillips added that he did not want industry participants to think that the attachment contains the modifications that will be made to the existing TLR process.

After further discussion, Mr. Desselle amended his motion to state: approve the NERC SAR to revise IRO-006 to NERC for further development and that Attachment C2 is not intended to be considered a part of the SAR, but a draft for informational purposes. Ms. Campbell agreed to the modification of the motion, and reiterated her second to the motion. The motion passed unanimously.

4. SAR to revise EOP-004, “Disturbance Reporting”

Mr. Benjamin reviewed the NERC SAR to revise EOP-004 “Disturbance Reporting” (This document is included as Item 4b in the Agenda packet). The purpose of this SAR is to study and understand the “disturbances or unusual occurrences that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions...to minimize the likelihood of similar events in the future.”



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Mr. Fidrych moved, seconded by Mr. Anderson, to assign the SAR to revise EOP-004 "Disturbance Reporting" to NERC for further development. The motion passed unanimously.

5. R05004 TTC/ATC/AFC/CBM/TRM in Requesting and Scheduling Transmission Service

Mr. Desselle stated that NAESB received revised Request No. R05004 from NERC on Monday, January 10, 2006 (This document is included as Item 5b in the Agenda packet). Mr. Lohrman reviewed this request. Request No. R05004 was originally submitted to NAESB by the NERC Long Term ATC/AFC Task Force. When the request was first presented to the JIC, NERC representatives requested that it be sent back to the requestor for clarification. Since the original requestor had been disbanded, NERC assigned the request to the ATC SAR Drafting Team. The modified request is the result of the work of that group. Mr. Lohrman stated that NERC is developing two complementary SARs in order to have companion reliability practices to the model business practices that are developed for Request No. R05004. It is the expectation that these two SARs will be presented to the JIC at its next meeting. Mr. Lohrman stated that he hoped that NERC and NAESB could form a joint team to work on these companion business practices and reliability standards together.

Since this request has been modified, it must be presented to the NAESB Triage Subcommittee. Mr. Lohrman suggested that the JIC postpone the vote on the assignment of this request until the next JIC meeting. There was no objection to Mr. Lohrman's suggestion.

5a. NERC SAR "Assess Transmission Future Needs"

The discussion of this SAR was postponed until the next JIC meeting.

5b. Discussion of JIC Agenda Process

The participants discussed whether a time limit of 10 business days notice should be implemented for inclusion of items on JIC Agendas for discussion/vote. Mr. Anderson suggested implementing the 10 business days notice limitation for items that will require action by the JIC. This limit can be waived by a vote during the JIC meeting. Items that only require discussion by the JIC would have a more flexible limitation for when they can be submitted for discussion at the JIC meeting. The participants agreed with Mr. Anderson's suggestions.

6. TLR Coordination Procedure

Mr. Desselle reviewed the history of the development of the TLR reliability standards and model business practices. He stated that Ms. McQuade and Mr. Benjamin were working to develop a coordination process for all future NAESB and NERC joint standards development, which would include TLR. Mr. Desselle noted that in addition to the work to develop a joint coordination process, the NAESB Board created a Board level Coordination Committee to work with NERC to modify the Memorandum of Understanding (MOU) as NERC becomes the ERO. Mr. Anderson stated that the reevaluation of the MOU should also include coordination of standards development efforts by NERC and NAESB.

Mr. Yeung offered that the coordination process between NERC and NAESB may include a measure to bring standards development SARs or Requests back to the JIC if they are withdrawn by the submitters. Mr. Yeung added that it is the specific opinion of the IRC that FERC Commissioners or staff should not be allowed to intervene in JIC decisions.



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Mr. Desselle responded that the NERC/NAESB Coordination procedure, and communication within the JIC are two different issues. He stated that he was open to proposals on how the MOU should be modified to address NERC/NAESB coordination as well as the JIC process.

Mr. Anderson suggested that the changes to the MOU should be considered for the JIC procedures to include a measure that requires NERC and NAESB to inform the JIC in a timely manner if one of the organizations is going to cease work on a particular standard. Mr. Berwager supported Mr. Anderson's suggestion and added that while the JIC cannot second guess the industry participants, when a decision is made at NERC or NAESB to withdraw a request or SAR, the JIC should be informed so the other organization can make a decision on whether to move forward with parallel efforts. Mr. Desselle stated that the suggestions would be considered in the Coordination Committee's consideration of modifications to the MOU.

7. Next Meeting

Mr. Benjamin stated he would poll the JIC members via e-mail regarding dates for the next JIC Meeting/Conference Call in February 2006. The agenda for the next JIC meeting should include NAESB Request Nos. R06002 and Revised R05004. The JIC will also discuss the Assess Transmission Needs SAR and have a progress report on the development of the coordination procedure.

8. Adjournment

The meeting adjourned by consensus at 3:24 PM Central. Transcripts can be ordered for this conference call, as for all JIC calls and meetings, by contacting the NAESB office.

9. JIC Member Attendance

NERC

Linda Campbell (JIC Co-Chairman)	Florida Reliability Coordinating Council
Scott Henry	Duke Power
Sam Jones	ERCOT ISO
Mark Fidrych	Western Area Power Administration

NAESB

Michael Desselle	American Electric Power
Lou Oberski	Dominion Resources
Barry Green	Ontario Power Generation
Ed Davis	Entergy Services, Inc.
Walt Yeager	Cinergy Services, Inc.
Syd Berwager	Bonneville Power Administration
John Anderson	Electricity Consumers Resource Council

ISO/RTO Council (IRC)

Charles Yeung	SPP
Kent Saathoff	ERCOT
Lisa Szot	CAISO
Diana Pommen (Alternate)	AESO
Ben Li	IESO



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10. Other Attendees

Chris Advena
Terry Bilke
Don Benjamin
LaRita Cormier
Victor Bissonette
Laura Kennedy
Larry Kezele
Bill Lohrman
John Lucas
Rae McQuade
Larry Middleton
Kathy York

PJM
MISO
NERC
Riverside Reporting
Hydro-Quebec Transenergie
NAESB
NERC
NERC
Southern Company
NAESB
MISO
TVA

E-mail completed form to mark.ladrow@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Transmission Relay Loadability
Request Date	January 09, 2006
Revised:	April 26, 2006

SAR Requester Information	SAR Type (Check box for each one that applies.)	
Name NERC System Protection and Controls Task Force (SPCTF)	<input checked="" type="checkbox"/>	New Standard
Primary Contact Charles Rogers, Chairman of SPCTF	<input type="checkbox"/>	Revision to existing Standard
Telephone (517) 788-0027 Fax (517) 788-0917	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail cwrogers@cmsenergy.com	<input type="checkbox"/>	Urgent Action

Purpose/Industry Need

Protective relays have contributed to virtually all major system disturbances including the Northeast Blackout of 1965, the New York Blackout of 1977, the WECC Blackouts of 1996, and the Blackout of August 14, 2003. During the 2003 blackout, relay loadability was found to have played a pivotal role in accelerating and spreading the early part of the cascade in Ohio and Michigan. Although the U.S.-Canada Power System Outage Task Force focused on the role played by "zone 3" relays, it was later found that other phase-distance and over-current relays also contributed to the cascade.

As a result, recommendations were made for the review of relay settings and the mitigation of zone 3 relays operating under load included in NERC Blackout Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S.-Canada Power System Outage Task Force Recommendation 21a, *Make More Effective and Wider Use of System Protection Measures*.

Over the last 18 months, the electric industry has been reviewing protection systems to determine their conformance with the loadability criteria set forth in those recommendations. The monumental effort to review and mitigate relay loadability issues done by the industry is to be applauded. However, those improvements to the protection systems cannot be allowed to lapse if relay loadability problems are to cease to be an ongoing contributor to system disturbances.

It is imperative to the continued reliability of the North American power system that the problems of relay loadability remain corrected and that the technical solutions are properly codified in NERC reliability standards.

Reliability Functions

The Standard will Apply to the Following Functions <i>(Check box for each one that applies.)</i>		
<input checked="" type="checkbox"/>	Regional Reliability Organization	Ensures the reliability of the bulk electric system within its Region.
<input type="checkbox"/>	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
<input type="checkbox"/>	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
<input type="checkbox"/>	Interchange Authority	Authorizes valid and balanced Interchange Schedules
<input type="checkbox"/>	Planning Authority	Plans the bulk electric system
<input type="checkbox"/>	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
<input type="checkbox"/>	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
<input type="checkbox"/>	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
<input checked="" type="checkbox"/>	Transmission Owner	Owens transmission facilities
<input type="checkbox"/>	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
<input checked="" type="checkbox"/>	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer
<input checked="" type="checkbox"/>	Generator Owner	Owens and maintains generation unit(s)
<input type="checkbox"/>	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
<input type="checkbox"/>	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
<input type="checkbox"/>	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
<input type="checkbox"/>	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles <i>(Check box for each one that applies..)</i>	
<input checked="" type="checkbox"/>	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.
<input type="checkbox"/>	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.
<input type="checkbox"/>	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.
<input checked="" type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input checked="" type="checkbox"/>	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? <i>(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)</i>	
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.)

Scope

The scope of the proposed standard would be to codify the relay loadability criteria and their implementation in accordance with the tenets of NERC Blackout Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S.-Canada Power System Outage Task Force Recommendation 21A, *Make More Effective And Wider Use Of System Protection Measures*, to ensure that protection systems and settings shall not limit transmission loadability, nor contribute to cascading outages.

Applicability

[Definition of Transmission Protection System Owners (TPSOs)

Entities that own and/or operate protective relaying systems applied to protect transmission facilities operated at 100 kV and above, including transformer banks with low-voltage terminals operated at 100 kV and above.]

1. This standard pertains to phase protection systems applied to:
 - a. Transmission lines operated at 200 kV and above
 - b. Transmission lines operated at 100 kV to 200 kV, identified by the Region as Operationally Significant Circuits.
 - c. Transformers with low voltage terminals connected at 200 kV and above voltage levels
 - d. Transformers with low voltage terminals connected at 100 kV to 200 kV, identified by the Region as Operationally Significant Circuits.
2. Any protective functions which could trip with or without time delay, on normal or emergency load current, including but not limited to:
 - a. Phase distance
 - b. Out-of-step tripping
 - c. Out-of-step blocking
 - d. Switch-on-to-fault
 - e. Overcurrent relays
 - f. Communications aided protection schemes including but not limited to:
 - i. Permissive overreach transfer trip (POTT)
 - ii. Permissive under-reach transfer trip (PUTT)
 - iii. Directional comparison blocking (DCB)
3. The following protection systems are excluded from requirements of this standard:
 - a. Relay elements that are only enabled when other relays or associated systems fail.
 - i. Overcurrent elements that are only enabled during loss of potential conditions.
 - ii. Elements that are only enabled during a loss of communications.
 - b. Protection systems intended for the detection of ground fault conditions

- c. Protection systems intended for protection during stable power swings.
 - d. Generator protection relays that are susceptible to load.
 - e. Relays elements used only for special protection systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.
4. This standard applies to the following entities:
 - a. Regional Reliability Organizations.
 - b. Transmission Owners that are Transmission Protection System Owners (TPSOs).
 - c. Generation Owners that are TPSOs.
 - d. Distribution Providers that are TPSOs.
 5. The standard will require that each RRO have a documented methodology for identifying its Operationally Significant Circuits and will require that each Regional Reliability Organization have a list of operationally significant circuits.
 6. The standard will require that each Transmission Owner, Generation Owner and Distribution Provider that is a Transmission Protection System Owner, comply with the transmission relay loadability criteria identified in the standard.

The standard should incorporate relay loadability criteria for all phase distance (including zone 3) and overcurrent relays, as well as, any protective functions which could trip with or without time delay, on normal or emergency load current. The Standard should specifically exclude: relay elements that are only enabled when other relays or associated systems fail, protection systems intended for the detection of ground fault conditions, protection systems intended for protection during stable power swings, generator protection relays that are susceptible to load, relays elements used only for special protection systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

The proposed standard should consider that during emergency loading conditions on the transmission system, the system operators should be making the human decision to open overloaded facilities, if conditions so warrant. Protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability criterion should be specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers. The system operator actions may include manual removal of the transmission circuit from service at any loading level in accordance with the transmission owner's operating policies and planned operating procedures, if doing so does not violate a system operating limit (SOL) or an interconnection reliability operating limit (IROL).

Additional Information

The [Working Paper on a Proposed Transmission Relay Loadability Standard](#), prepared by the System Protection and Controls Task Force includes a proposed draft Transmission Relay Loadability Standard that codifies the relay loadability criteria prescribed in the NERC and U.S.-Canada Power System

Outage Task Force recommendations on relaying. It is available on the NERC SPCTF website using the hotlink above. That working paper was prepared to assist the Standards Authorization Committee and its SAR and/or standards drafting team in the development of the proposed standard. This working paper takes full advantage of the recent experience of applying those criteria to the EHV transmission system (200 kV and above) and ongoing work on the 100-200 kV Operationally Significant Circuits.

Additional technical information can also be found in [EHV Transmission System Relay Loadability Review and Requests for Temporary and Technical Exceptions](#) report and [Protection System Review Program - Beyond Zone 3](#) report at the NERC website

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

E-mail completed form to: mark.ladrow@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Violation Risk Factors
Request Date	January 5, 2006

SAR Requestor Information	SAR Type (Put an 'x' in front of one of these selections)	
Name Stan Kopman, chair	<input type="checkbox"/>	New Standard
Primary Contact: Stan Kopman	<input checked="" type="checkbox"/>	Revision to existing Standard
Telephone (212) 840-1070 Fax (212) 302-2782	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail skopman@npcc.org	<input type="checkbox"/>	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

This SAR proposes a matrix that assigns a risk of high, medium, or lower for all of the requirements contained in the reliability standards. This assignment provides a baseline understanding of the risk that a violation of a requirement poses to the bulk power system. This factor will be used when determining a penalty or sanction for a violation of that requirement.

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies by double clicking the grey boxes.)		
<input checked="" type="checkbox"/>	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
<input checked="" type="checkbox"/>	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
<input checked="" type="checkbox"/>	Interchange Authority	Authorizes valid and balanced Interchange Schedules
<input checked="" type="checkbox"/>	Planning Authority	Plans the bulk electric system
<input checked="" type="checkbox"/>	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
<input checked="" type="checkbox"/>	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
<input checked="" type="checkbox"/>	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
<input checked="" type="checkbox"/>	Transmission Owner	Owens transmission facilities
<input checked="" type="checkbox"/>	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
<input checked="" type="checkbox"/>	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer
<input checked="" type="checkbox"/>	Generator Owner	Owens and maintains generation unit(s)
<input checked="" type="checkbox"/>	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
<input checked="" type="checkbox"/>	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
<input checked="" type="checkbox"/>	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
<input checked="" type="checkbox"/>	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles (Check boxes for all that apply by double clicking the grey boxes.)	
<input checked="" type="checkbox"/>	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.
<input checked="" type="checkbox"/>	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.
<input checked="" type="checkbox"/>	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.
<input checked="" type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
<input checked="" type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
<input checked="" type="checkbox"/>	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.)

The requirements associated with each NERC reliability standard have been assigned a level of risk; high, medium, or lower, based on the detrimental effect a violation of the requirement could have on the reliability of the bulk power system. These levels of risk are in a matrix that, if approved, will become an addendum to the existing reliability standards and included in the body of the newly developed standards.

These proposed initial risk factors were assigned by the SAR drafting team. Risk factors for new standards and requirements are proposed to be created by the standard drafting teams using criteria that will be included in the Reliability Standards Process Manual. The risk factors from this matrix will be inserted into the proper standard as each reliability standard comes up for its five-year review. At that time, the requirement and risk factor will be retired from the addendum.

All proposed risk factors will be posted for stakeholder comment prior to being balloted. For violation risk factors being developed for already approved standards, a matrix of risk factors will be balloted. In the future, risk factors will be added to each requirement by the associated standard drafting team. The risk factors will become a part of the standard and will be subject to stakeholder comment and balloting.

The Need for Violation Risk Factors

Since their inception, the NERC Reliability Standards have not included approved indicators of the relative risk of non-compliance. Without these indicators, it is difficult for the industry, regulators, and public to understand the risk that violations can have on the bulk electric system. From standard to standard, the current noncompliance levels do not provide a consistent indication of relative risk to the bulk electric system.

The proposed violation risk factors are designed to indicate the potential reliability impact of violating a standard requirement. Assigning a risk factor to each requirement is fundamental to implementing the ERO Sanction Guidelines if NERC becomes the ERO. The existing levels of noncompliance for each standard, when used with the existing penalty matrix, are based on a limited amount of information that makes it difficult to develop a fair or meaningful penalty or sanction for a violation. A new and more consistent method that relies on the violation risk factor to create the base penalty in the ERO Sanction Guidelines has been developed. The ERO Sanction Guidelines document is part of the NERC's ERO Application and will be used to determine penalties and sanctions when a requirement is violated.

Development of the Violation Risk Factors

The SAR drafting team developed the initial violation risk factors, using the definitions contained in the list and assigned a violation risk factor of high, medium, or lower to each currently approved standard requirement.

Definition of Risk Factors

The requirements associated with each of NERC reliability standards have been assigned a level of risk; high, medium, and lower, based on the detrimental effect a violation of the requirement could have on the reliability of the bulk power system. The following definitions were applied to determine the assignment of risk for each requirement:

High Risk Requirement

a. A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or

b. A requirement in a planning time frame that, if violated, could, under emergency, abnormal or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

a. A requirement that, if violated, could directly and adversely affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or

b. A requirement in a planning time frame that, if violated, could, under emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

a. A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature; or

b. A requirement in a planning time frame that, if violated, would not, under the emergency, abnormal or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Other Relevant Standards Activities

The violation risk factors are part of a larger plan to improve the standards process and the standards themselves. Also attached is the White Paper on Guidelines for Compliance Information in Support of Reliability Standards that was approved by both the Standards Authorization Committee and the Compliance and Certification Committee (CCC). The paper outlines the proposed changes to the Reliability Standards Process Manual that includes restructuring the compliance elements in the standards. Some of the compliance elements currently contained in the standards will be moved to a manual administered by the CCC. An open process to develop, revise, and approve compliance elements for a new or revised standard will parallel the development of that particular standard. Violation risk factors, however, would be included as part of each standard requirement. They would be developed by the subject matter experts on the standard drafting teams and reviewed and approved by the industry in accordance with the standards ballot process.

Related Standards

Standard No.	Explanation
All	All standards that are in effect as of 1/1/2006 have violation risk factors developed. Those approved after that date but before the final risk violation factors standard is balloted will have factors developed so no requirements are left without factors.

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Related SARs

SAR ID	Explanation
Reliability Standards Process Manual	The Reliability Standards Process Manual is undergoing proposed changes; additional changes would be required.
Provide Missing Measures and Compliance Elements in Existing Standards	This is a parallel effort to clarify compliance enforcement elements in the standards for consistency.

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

E-mail completed form to mark.ladrow@nerc.net

Standard Authorization Request Form

Title of Proposed Standard Revision to IRO-004 (Reliability Coordination – Operations Planning) to require timely submission of system reliability data

Request Date 1-19-2006

SAR Requestor Information	SAR Type (Check a box for each one that applies.)	
Name Julie Pierce	<input type="checkbox"/>	New Standard
Primary Contact Julie Pierce	<input checked="" type="checkbox"/>	Revision to existing Standard
Telephone (651) 632-8445 Fax (651) 632-8417	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail jpierce@midwestiso.org	<input type="checkbox"/>	Urgent Action

Purpose (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

This SAR is required to revise IRO-004-0 Requirement 4 to require the submission of system operational data by noon the day prior as soon as it is known to be in effect for the next day. The Interchange Distribution Calculator Working Group (IDCWG) and the Operating Reliability Subcommittee (ORS) reviewed Section A (System Data Exchange (SDX) – Eastern Interconnection) of the Reliability Coordinator Reference Document contained in the NERC Operating Manual, and concluded that the existing reliability standards do not adequately address the requirements placed on reporting entities within the reference document. Therefore, the IDCWG and the ORS support a revision to IRO-004-0 to require the timely submission of system operation data used by reliability coordinators, transmission operators, and balancing authorities to perform next day operational analysis. This SAR would also modify the Compliance Section of IRO-004.

Standards Authorization Request Form

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

Existing reliability standards do not adequately address the requirements for the submission of system operational data, used in Available Transfer Capability calculations, the Transmission Loading Relief application, and power system applications, from Balancing Authorities, Transmission Owners/Operators, Generation Owners/Operators, and Load Serving Entities to their Reliability Coordinator. Section A, (System Data Exchange (SDX) – Eastern Interconnection), of the Reliability Coordinator Reference Document, addresses the submission of specific system operational data, including the timing associated with the submission of the data. However, the data submission specifications outlined in the Reliability Coordinator Reference Document are not uniformly followed within the Eastern Interconnection. Therefore, the IDCWG and the ORS support a revision to IRO-004 to require timely submission of system operational data.

Standards Authorization Request Form

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

The IDCWG and the ORS propose revising Requirement 4 of IRO-004 as follows: R4. Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity in the Reliability Coordinator Area shall provide information required for system studies, such as critical facility status, Load, generation facility, operating reserve projections, and known Interchange Transactions. This information shall be available as soon as it is known by the Eastern Interconnection Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load Serving Entity and will be submitted with the next hourly system data exchange update. This information shall be made available by 1200 Central Standard Time for the Eastern Interconnection 1200 Pacific Standard Time for the Western Interconnection.

For the purpose of clarifying Requirement R4 add a footnote that states: Critical facility, as defined in this document, shall be any principle bulk electric facility that may be adversely affected by a contingency in another system of if a NERC System Operating Limit or Interconnection Reliability Operating Limit exists for the facility

At a minimum, the critical facility statuses shall include for each entity:

1. Any transmission equipment 100 kV and above
2. Any generation facility 20 MW and above

The IDCWG and ORS also propose revised the Compliance Section of IRO-004, specifically the "Levels of Non-Compliance" as follows:

Level 1: System studies were not conducted for one day in a calendar month, ~~and/or~~ the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations, or load data and known critical facility outages for the next day that were not reported to the NERC system data exchange by noon central prevailing time the day prior.

Level 2: System studies were not conducted for 2-3 days in a calendar month, ~~and/or~~ the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations, or load data and known critical facility outages for the next day that were not reported to the NERC system data exchange by noon central prevailing time the day prior for 2-3 days in a calendar month.

Level 3: System studies were not conducted for 4-5 days in a calendar month, ~~and/or~~ the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations, or load data and known critical facility outages for the next day that were not reported to the NERC system data exchange by noon central prevailing time the day prior for 4-5 days in a calendar month.

Level 4: System studies were not conducted for more than 5 days in a calendar month, ~~and/or~~ the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations, or load data and known critical facility outages for the next day that were not reported to the NERC system data exchange by noon central prevailing time the day prior for more than 5 days in a calendar month.

Standards Authorization Request Form

Reliability Functions

The Standard will Apply to the Following Functions <i>(Check box for each one that applies.)</i>		
<input checked="" type="checkbox"/>	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest Reliability Authority.
<input checked="" type="checkbox"/>	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.
<input type="checkbox"/>	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
<input type="checkbox"/>	Planning Authority	Plans the Bulk Electric System.
<input type="checkbox"/>	Resource Planner	Develops a long-term (>one year) plan for the resource adequacy of specific loads within a Planning Authority area.
<input type="checkbox"/>	Transmission Planner	Develops a long-term (>one year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
<input type="checkbox"/>	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
<input checked="" type="checkbox"/>	Transmission Owner	Owns transmission facilities.
<input checked="" type="checkbox"/>	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders.
<input type="checkbox"/>	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.
<input checked="" type="checkbox"/>	Generator Owner	Owns and maintains generation unit(s).
<input checked="" type="checkbox"/>	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
<input type="checkbox"/>	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity, and all necessary Interconnected Operations Services as required.
<input type="checkbox"/>	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
<input checked="" type="checkbox"/>	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user.

Reliability and Market Interface Principles

Applicable Reliability Principles <i>(Check box for all that apply.)</i>	
<input checked="" type="checkbox"/>	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.
<input type="checkbox"/>	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.
<input checked="" type="checkbox"/>	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.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
<input type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
<input checked="" type="checkbox"/>	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? <i>(Select 'yes' or 'no' from the drop-down box.)</i>	
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	

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

When completed, email to: gerry.cauley@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Assess Transmission Future Needs and Develop Transmission Plans
Request Date	May 01, 2004

SAR Requestor Information	SAR Type (Put an 'x' in front of one of these selections)	
Name Paul Rocha	<input checked="" type="checkbox"/>	New Standard
Primary Contact Paul Rocha	<input type="checkbox"/>	Revision to existing Standard
Telephone (713) 207-2768 Fax	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail paul.rocha@centerpointenergy.com	<input type="checkbox"/>	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

To establish a standard for assessing and planning the transmission systems in North America. The transmission system must be assessed and planned to ensure that it performs its intended functions in providing reliable delivery of power for the future needs of customers.

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies by double clicking the grey boxes.)		
<input checked="" type="checkbox"/>	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
<input type="checkbox"/>	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
<input type="checkbox"/>	Interchange Authority	Authorizes valid and balanced Interchange Schedules
<input checked="" type="checkbox"/>	Planning Authority	Plans the bulk electric system
<input type="checkbox"/>	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
<input checked="" type="checkbox"/>	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
<input type="checkbox"/>	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
<input checked="" type="checkbox"/>	Transmission Owner	Owns transmission facilities
<input type="checkbox"/>	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
<input type="checkbox"/>	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
<input type="checkbox"/>	Generator Owner	Owns and maintains generation unit(s)
<input type="checkbox"/>	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
<input type="checkbox"/>	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
<input type="checkbox"/>	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
<input checked="" type="checkbox"/>	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles (Check boxes for all that apply by double clicking the grey boxes.)	
<input checked="" type="checkbox"/>	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.
<input type="checkbox"/>	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.
<input checked="" type="checkbox"/>	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.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
<input type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
<input type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
<input type="checkbox"/>	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.)

The Standard shall establish requirements for assessing the performance of planned bulk electric transmission systems and the requirements for documenting plans to remedy any inadequacies identified in the process of conducting such assessments.

The scope of such assessments and plans is for a future planning period (planning horizon) starting at one year and extending to five years or more.

The planning horizon must be long enough to permit timely implementation of viable solutions to remedy the potential inadequacies found. Planning horizons beyond 5 years may be needed to meet regulatory or legislative requirements, or may be based on the judgment of the Transmission Planner or Planning Authority.

The scope *does not* include the operating horizon less than one year. While the planning horizon is intended to provide sufficient time for facility additions, there is no intent to exclude appropriate operating procedures as options to correct potential transmission inadequacies. Such procedures should also be included in the Transmission Plan.

The Standard will consider the transition from the operating horizon to the planning horizon. In particular, the Standard will assure consistency between reliability requirements set forth in the Standards for Planning (for example, this Standard 500, "Assess Transmission Future Needs and Develop Transmission Plans") and similar criteria required by other Standards (such as Standard 600, "Determine Facility Ratings, Operating Limits and Transfer Capabilities"), which also apply in operations.

In addition, the Standard shall explain the relationship between the reliability requirements for operations and those for planning, so that differences are better understood.

The Standard shall identify reliability performance requirements, but shall not specify *how* to achieve such performance requirements.

The applicable portions of the following existing NERC Planning Standards will be used as the starting point in drafting these requirements:

- I.A Transmission Systems
- I.B Reliability Assessment
- I.D Voltage Support & Reactive Power
- II.A System Data
- II.D Actual and Forecast Demands

The Standard shall require that system models be developed, maintained and shared in a manner consistent with the Functional Model and appropriate information-sharing policies. Included will be requirements that each Planning Authority and Transmission Planner document modeling assumptions, including the methodology used for incorporating planned generation assets (including transfers) in the model, as well as how such generation is dispatched. The Standard shall consider a requirement for Load Serving Entities (LSEs) to provide forecast resource data for input to the models.

While methodologies and assumptions must be documented, the Standard will *not* prescribe specific tools to be used in the performance assessment of the planned systems.

The Standard will identify the various planning functions that are responsible for compliance with the standard criteria. The assignment of compliance responsibility will be consistent with the Functional Model.

This Standard will *not* include requirements for:

- Resource Planning (i.e., assessing or ensuring the availability of adequate aggregate generation resources to serve aggregate load).
- Planning generation additions to remedy any aggregate generation resource inadequacies.
- Developing Transmission Plans to mitigate congestion due to economy transfers of generation resources.

However, the Standard should neither preclude nor require the consideration of generation or load (demand side management) as alternatives to transmission reinforcement/reconfiguration when developing solutions to potential transmission inadequacies.

While the Standard should start from and closely align with the existing Planning Standards I.A, I.B, I.D, II.A, and II.D, the system conditions to be studied or assessed may need to be better defined or clarified.

Examples of areas that should be considered for clarification in the Standard include:

- The Standard should clarify that the requirement to assess the performance at *all* demand levels does not mean that a multitude of transmission models need to be created for every possible demand level, only that a representative sample covering critical operating conditions needs to be modeled in accordance with regionally-defined criteria.
- The Standard should provide a clearer definition of “cascading outages”, including what constitutes a cascading state. The Standard should also consider providing a clearer definition of “system stable”. These definitions must be coordinated and consistent with definitions in other new Standards being drafted by NERC, such as Standards 200 and 600.
- The Standard should take into account the variability of generation, including unit maintenance outages, weather and time of day. Variability of load due to factors such as weather and time of day should also be considered.
- The Standard should continue to use deterministic criteria. The criteria embodied in Table 1 of existing Planning Standard I.A shall be used as a starting point. Following a review of the likelihood, duration, impact of events, and definition of applicable ratings (A/R) in existing Table I, a re-classification of Table I events should be considered, as necessary, for inclusion in the new Standard.

Other changes should be considered for incorporation into the new Standard. Such changes could include:

- (1) Addition or deletion of categories/events/performance requirements.
- (2) Use of probabilistic planning methods.
- (3) Re-definition of categories (e.g., categories determined by event probability levels or ranges).
- (4) Differences in requirements for an event based on a range of event probabilities (for example, recognize that longer lines have a greater probability of outage than shorter lines).

(5) An alternative table, similar to Table I of existing Planning Standard I.A, except allowing for probabilistic planning criteria.

(6) Provision for a specific facility with an abnormal outage probability to have different performance requirements.

The list above is intended to be illustrative and not exhaustive or mutually exclusive. As allowed by the Standards Development Process, Regions may submit Regional Differences.

- Existing Planning Standard S1, S2, S3, S4 and Table I, Categories A, B, C, and D should be clarified on the issue of how a planned outage should be used in an assessment.

The Standard should specify whether the planned outage requirement should be retained for Categories B and C. If retained, the requirement should be clarified in such a way that it can be practically implemented. In particular, the Transmission Planner should not be required to exhaustively test its system for every conceivable planned outage (including maintenance outages) in addition to every conceivable Category B and C contingency. The Standard should clarify that the planned outage requirement does not apply to Categories A and D.

- The Standard should address and rectify ambiguities in performance requirements, specifically cascading outages and applicable ratings (A/R). This applies to all Categories, especially Category C.

For example, the Standard should clarify tests used for considering cascading, such as divergent power flow, post-contingency overload limits, voltage magnitudes, etc. The Standard should also clarify that different ratings may be applicable to different categories of events and perhaps different types of events within a category (specified by entities in accordance with Standard 600).

- The Standard should include requirements to ensure that the maximum available short circuit current does not exceed facility owner specifications.
- The Standard should also address requirements on reactive planning with specific reference to steady state and transient voltage stability criteria.
- The Standard should address requirements for reporting (perhaps to the Regions) on the progress or status of implementing the plans developed in accordance with the Standard. However, any such reporting requirements should be consistent with the Resource & Transmission Adequacy Task Force Recommendation #2, and should not impose undue burdens upon transmission entities

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation
FACILITY_RATINGS_01_01	<i>“Determine Facility Ratings, Operating Limits and Transfer Capabilities”</i> . The Planning Standard will use some data collected within the “Facility Ratings” SAR. The Draft “Facility Ratings” Standard, Section 603, establishes some guidelines for the planning function to set operating limits based on Table 1 of the existing Planning Standard I.A.
OPER_WITHN_LMTS_01_01	<i>“Operate Within Interconnection Reliability Operating Limits”</i> . This Planning Standard needs to establish future planning criteria such that the bulk electric power system can be operated within operating limits.

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	Explanation
Planning Std. I.A	Transmission Systems: Plan within ratings, avoid cascading outages, uncontrolled system separation, and voltage and transient instability.
Planning Std. I.B	Reliability Assessment
Planning Std. I.D	Voltage Support & Reactive Power
Planning Std. II.A	System Data
Planning Std. II.D	Actual & Forecast Demands

MAPP & MEC believe the following information supports our proposed new reclassification by demonstrating that the events that MAPP & MEC recommend for reclassification are the low probability Category C events. MAPP & MEC recognize that published outage data are subject to interpretation, potential inaccuracy, and change through time; however, we believe that MAPP & MEC operating experience with transmission element outages supports the statistical summary provided in the following table.

Contact info:

Tom Mielnik, Chair
MAPP Planning Standards Development Working Group
MidAmerican Energy Company
106 East Second Street
Davenport, Iowa 52801
(563)333-8129
tcmielnik@midamerican.com

345 kV Outage Data				
Contingency	Outage Rate, occ./year	Duration, hours	Probability	Relative Likelihood
Generator B1	9	81	0.08321918	1
Two generators C3	1.5	40.5	0.00693493	12
Bipolar DC line * (Similar to B4)	1.41	21	0.00338014	24
Line * B2	0.8065	18	0.00165719	50
Transformer B3	0.0642	157	0.00115062	72
Bipolar DC Line * + Generator (Sim. to 1 Pole DC line + gen. C3)	0.1478	16.68	0.00028143	296
Line * + Generator C3	0.0820	14.7	0.00013760	605
Generator + Transformer C3	0.0157	53.4	0.00009571	870
Common tower * C5	0.007	113	0.00009030	922
Breaker Failure- Insulation Breakdown C2 RECLASSIFY THIS EVENT	0.001423	163	0.00002647	3,144
Bipolar DC line *+Bipolar DC line * (Sim. to Two 1 Pole DC lines - C3) RECLASSIFY THIS EVENT	0.009532	10.5	0.00001143	7,281
Stuck breaker C6-C9 RECLASSIFY THIS EVENT	0.00635	4	0.00000290	28,696
Line * + Line * (independent) C3 RECLASSIFY THIS EVENT	0.00267	9	0.00000275	30,262
Line * + Transformer C3 RECLASSIFY THIS EVENT	0.0010	16.1	0.00000184	45,228
Two transformers C3 RECLASSIFY THIS EVENT	0.00014774	78.5	0.00000132	63,045
Bus Section** RECLASSIFY THIS EVENT	0.0023	4.7	0.00000123	67,438

* Per 100 mile-year.

** Based upon 230 kV data.

References

1. MAPP-CSRWG, "MAPP Bulk transmission system outage report", June 2001.
2. C. R. Heising, et al, "Final report on high voltage circuit breaker reliability data for use in substation and system studies - report on behalf of WG 13.06, in Proceedings of CIGRE Conference, Paris, 1994.
3. R. Billinton, A. A. Chowdhury, "Generating unit models using the Canadian Electricity database", CEA Transactions, Volume 23, 1984.
4. R. N. Allan, "Concepts of data for assessing the reliability of composite systems", IEEE Tutorial Course on Reliability Assessment of Composite Generation and Transmission Systems, Course Text 90EH0311-1-PWR.

BPA Data

Category	Contingencies	Outages per year	Source of Data
B1	Generator	4	NW Federal system is mostly hydro generation in remote locations and these outages are usually of little consequence to the power system. These outage data are based on three thermal plants located in load areas. Due to the small size of this sample, they may not be very useful. These outages average 109 hour duration.
B2	Transmission Circuit	0.97	BPA data for 225 lines 200-kV through 550-kV, 1985-2003 data (19 years), average length 50.5 miles, outages with duration greater than 1 minute only. Five hour average duration.
B3	Transformer	0.037	IEEE Paper 91 SM 442-4 PWRS, BPA autotransformers, winding voltages 115 to 550-kV. 28 day average duration.
B4	Single Pole DC Line	9	BPA data for PDCI, 845 miles (one line only). 8.99 outages per year with total annual outage time of 170 hours. Not including terminal outages. 19 hour average duration.
C1	Bus section	0.00733	BPA data for 115 stations with voltages between 230-kv through 500-kV, 17.8 years of data, resulting in 15 events.
C2	Breaker internal fault	0.00079	1994 CIGRE Brochure 83: data for 230 and 500-kV breakers: insulation breakdown.
C2	Breaker fails to open	0.00569	1994 CIGRE Brochure 83: data for 230 and 500-kV breakers: failure to open.
C3	Two Line Dependent	0.08700	BPA data for sustained multiple outages (greater than one minute) for its 500-kV lines, 1985-2003 data (19 years). Calculated for two lines with 50 mile common corridor length.
C3	Two Line Independent	0.00110	Calculated based on single contingency rate indicated above: 1 outage per year with duration of 5 hours
C3	Generator and Transformer	0.01400	Calculated based on single contingency outage rates indicated above: 0.037 outages per year of duration 28 days for transformers and 4 outages per year of duration 109 hours for generators.
C3	Line and Transformer	0.00290	Calculated based on single contingency outage rates indicated above: 1 outage per year of duration 5 hours for line and .037 outages per year of duration 28 days for transformer.
C3	Two Generator	0.45000	Calculated based on single contingency outage rate indicated above: 4 outages per year with duration 109 hours each. Small sample of data - may not be representative.

C3	Line and Generator	0.05500	Calculated based on single contingency outage rates indicated above: 1 outage per year of duration 5 hours for line and 4 outages per year of duration 109 hours for generator.
C4	Bipolar DC Line	0.35000	Calculated based on single contingency outage rate indicated above: 9 outages per year for duration of 19 hours
C5	2 circuits on multiple towerline	0.05100	BPA data for sustained multiple outages (greater than one minute) for its 500-kV double circuit lines, 1985-2003 data (19 years). Calculated for double circuit line with 50 mile length.
C6, C7, C8, C9	Protection failure	0.11969	BPA Data for 115 stations with voltages 230 through 500-kV, 17.8 years of data, resulted in 245 events of pretection failure.
C6	SLG Fault Generator with protection failure	0.47875	Generator single contingency outage rate from above multiplied by protection failure rate (0.11969)
C7	SLG Fault Transmission circuit with protection failure	0.11490	Transmission line single contingency outage rate from above multiplied by protection failure rate (0.11969)
C8	SLG Fault Transformer with protection failure	0.00443	Transformer single contingency outage rate from above multiplied by protection failure rate (0.11969)
C9	Bus section fault with protection failure	0.00088	Bus fault outage rate from above multiplied by protection failure rate (0.11969)

Data provided by Marv Landauer based on outage data collected by BPA.

R05020

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or
Electronic Transaction

or

Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or
Electronic Transaction

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
1301 Fannin, Suite 2350
Houston, TX 77002

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

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

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

Please note that submitters should provide the requests to the NAESB office in sufficient time so that the NAESB Triage Subcommittee may fully consider the request prior to taking action on it. It is preferable that the request be submitted a minimum of 3 business days prior to the Triage Subcommittee meetings. Those meeting schedules are posted on the NAESB web site at http://www.naesb.org/monthly_calendar.asp.

R05020

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or
Electronic Transaction

or

Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or
Electronic Transaction

Date of Request: 06/06/05

1. Submitting Entity & Address:

Bill Blevins
116-390 Village Blvd
Princeton, NJ 08540
United States

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

Name : Bill Blevins
Title : Manager Interchange
Phone : (609) 452-8060
Fax : (609) 452-9550
E-mail : Bill.Blevins@nerc.net

3. Description of Proposed Standard or Enhancement:

This request is to include a guideline for rounding schedules with partial mWh's in the
coordinate interchange business practice WEQBPS-002-000.

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):

This business practice will be used to aid company after the fact that accounting check outs.

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

Tangible benefits will be that disputes based on rounding of partial mWh schedules will be eliminated since guidance will be provided.

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

There should be no incremental cost. Some companies may have to go back and reprogram their accounting systems based on the guidance developed from this business practice.

7. Description of Any Specific Legal or Other Considerations:

Tariffs or business rules may be established locally by some companies which differ from standard accounting rules for rounding these schedules but the decrease in disputed values should warrant the development of standard accounting rules for scheduled transactions that have hours containing partial mWh's.

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

General rounding rule will need to be developed prior to testing.

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

R06006

North American Energy Standards Board

**Request for Initiation of a NAESB Business Practice Standard, Model Business Practice
or Electronic Transaction**

or

**Enhancement of an Existing NAESB Business Practice Standard, Model Business
Practice or Electronic Transaction**

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
1301 Fannin, Suite 2350
Houston, TX 77002

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

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

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

Please note that submitters should provide the requests to the NAESB office in sufficient time so that the NAESB Triage Subcommittee may fully consider the request prior to taking action on it. It is preferable that the request be submitted a minimum of 3 business days prior to the Triage Subcommittee meetings. Those meeting schedules are posted on the NAESB web site at http://www.naesb.org/monthly_calendar.asp.

R06006

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

or

Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

Date of Request: February 23, 2006

1. Submitting Entity & Address:

Joint Interchange Scheduling Work Group

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

Name : Bob Harshbarger
Title : OASIS Trading Manager
Phone : 425.462.3348
Fax : 425.462.3049
E-mail : robert.harshbarger@pse.com

3. Description of Proposed Standard or Enhancement:

Registered Market Operators may request changes to the Market Level profile of Implemented Interchange. Such change requests only require the approval of the Source and Sink Balancing Authorities and will not be deemed Late.

To support this change, the e-Tag specification will need to be modified as follows: the processing of Market Level profile change requests submitted by registered Market Operators will utilize the same timing and approval mechanisms as Reliability Level profile change requests.

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

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):

This standard will allow Market Operators to adjust Implemented Interchange as a result of their market results. Typically, the Market Operator will conduct a market into which participants will submit transactions. These transactions may be represented in e-Tags at their desired Market Level. After the Market Operator's market closes, it may be necessary to reflect changes to the original transactions by adjusting the associated e-Tag.

Currently, the e-Tag specification recognize Market Operators and their ability to request adjustments to the Market Level profile, but as with any Market Level profile change request, it requires the approval of all reliability entities associated with that transaction. In addition, the change request can be deemed Late by the e-Tag system which defaults the requests to Denied should not all approval entities respond.

This standards request will introduce the Market Operator's role in the Interchange Coordination Standards and stream line the approval process to ensure reliability entities and tools (i.e., the Interchange Distribution Calculator) are notified of changes to the transactions.

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

This standards request will introduce the Market Operator's role in the Interchange Coordination Standards and stream line the approval process to ensure reliability entities and tools (i.e., the Interchange Distribution Calculator) are notified of changes to the transactions. It will no longer be necessary for Market Operators to request adjustment to the reliability level for non-reliability reasons.

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

It is thought that this change to the e-Tag specification would result in minimal changes to the Authority Service software.

7. Description of Any Specific Legal or Other Considerations:

A companion NERC Standards Authorization Request (SAR), addressing the obligations of the reliability entities to the market operators' adjustment requests, is being submitted to NERC.

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

Unknown.

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

Unknown.

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

None.

RD5019

North American Energy Standards Board

**Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction
or
Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or Electronic Transaction**

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
1301 Fannin, Suite 2350
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.

Please note that submitters should provide the requests to the NAESB office in sufficient time so that the NAESB Triage Subcommittee may fully consider the request prior to taking action on it. It is preferable that the request be submitted a minimum of 3 business days prior to the Triage Subcommittee meetings. Those meeting schedules are posted on the NAESB web site at http://www.naesb.org/monthly_calendar.asp.

RO5019

North American Energy Standards Board

**Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction
or
Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or Electronic Transaction**

Date of Request: **June 24, 2005**

1. Submitting Entity & Address:

**NAESB/NERC Joint Interchange Scheduling Task Force
1301 Fannin, Suite 2350
Houston, TX 77002**

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

Name : **Paul Sorenson**
Title : **DATI Director Central Markets Strategy**
Phone : **612-360-1633**
Fax :
E-mail : **paul.sorenson@oati.net**

3. Description of Proposed Standard or Enhancement:

Pro Forma tariff includes provisions for higher priority service requests to displace or interrupt lower priority requests. For firm services, this displacement process is limited to services which are conditional (i.e., more than one day in advance for daily, etc.) and affords the customer being displaced a "right of first refusal" to match the higher priority request to retain service. Other than several data elements in the DASIS S&CP (COMPETING_REQUEST flag, MATCHING request type, etc.) there is not a recognized standard business practice regarding the conduct of displacement/interruption and exercising the right of first refusal.

This standard request is for the development of business practice standards and any necessary revisions in the DASIS S&CP to clearly document the procedure to be used by Transmission Providers and Transmission Customers to implement the displacement/interruption terms of the Pro Forma tariff. The following guidelines should be considered in the standard recommendation:

- **must address both Firm and Non-Firm Point-to-Point transmission services**
- **must account for displacement of service in-whole or in-part**
- **must minimize the potential for any "gaming" opportunities between competing customers**
- **should recognize existing standards from Order 638 re: competing requests and negotiations**
- **should specify exactly what constitutes a "matching" request with regard to term, service, and capacity necessary to retain transmission service rights**

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):

Section 4.2.13.6 and 4.2.13.7 describe a process to be used on OASIS for handling competing requests and implementation of right of first refusal. This description does not provide enough specificity to document a full business practice with respect to implementing the terms of the Pro Forma tariff. This standard request should address the key aspects of the Pro Forma tariff with respect to handling of competing requests. The OASIS standards may require modification to accommodate these business practice standards.

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

Due to lack of specificity in the existing standards, there are inconsistencies between Transmission Providers in their implementation of the terms of the Pro Forma tariff with respect to competing requests and the right of first refusal. This standards request would provide certainty for Transmission Customers of exactly how each Provider would handle competing requests and the process to be implemented on OASIS for this process.

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

7. Description of Any Specific Legal or Other Considerations:

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

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

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

Consult OASIS S&CP Section 4.2.13.6 and 4.2.13.7 and OASIS Business Practices 4.14 through 4.27.

Item 5b

Upcoming NERC meetings

Date & Time	Group	Staff	City	Registration Link	Details
6/21/2006: 12:00:00 PM - 5:00:00 PM 6/22/2006: 8:00:00 AM - 5:00:00 PM 6/23/2006: 8:00:00 AM - 12:00:00 PM	SAC	Maureen Long	Philadelphia	Required	Details
9/13/2006: 9:00:00 AM - 12:00:00 PM	PC/OC Joint	Don Benjamin	Baltimore or Boston	Not Yet Available	Details
9/13/2006: 1:00:00 PM - 5:00:00 PM 9/14/2006: 8:00:00 AM - 12:30:00 PM	PC	Don Benjamin	Baltimore or Boston	Required	Details
9/13/2006: 1:00:00 PM - 5:00:00 PM 9/14/2006: 8:00:00 AM - 5:00:00 PM	OC	Don Benjamin	Baltimore or Boston	Not Yet Available	Details
9/28/2006: 8:00:00 AM - 5:00:00 PM 9/29/2006: 8:00:00 AM - 12:00:00 PM	SAC	Maureen Long	Quebec City	Not Yet Available	Details
12/6/2006: 1:00:00 PM - 5:00:00 PM 12/7/2006: 8:00:00 AM - 5:00:00 PM	OC	Don Benjamin	Houston or Tampa	Not Yet Available	Details
12/13/2006: 12:00:00 PM - 5:00:00 PM 12/14/2006: 8:00:00 AM - 5:00:00 PM 12/15/2006: 8:00:00 AM - 12:00:00 PM	SAC	Maureen Long	Tampa	Not Yet Available	Details