Balancing Authority Controls SAR Drafting Team Meeting

October 16, 2007 — 8 a.m. to 5 p.m. Central Time
October 17, 2007 — 8 a.m. to 3 p.m. Central Time

Four Points by the Sheraton
10249 W. Irving Park Road
Schiller Park, Illinois
847.671.6000

Agenda

1) Administrative
   a) Introduction of Participants
   a. Review Antitrust Guidelines (**Attachment 1**)
   b) Review Meeting Objectives:
      - Ensure all team members know what the Standards Committee expects of them
      - Draft responses to each comment submitted on the first posting of the SAR
      - Modify the SAR based on discussion of comments submitted on the first posting of the SAR
      - Draft a SAR Comment Form for the next posting
      - Agree to a project schedule
2) Review Standard Committee Expectations (**Attachment 2**)
3) Prepare Comment Responses (**Attachments 3 & 4**)
4) Modify SAR (**Attachment 5**)
5) Review Project Schedule (**Attachment 6**)
6) Summarize Action Items
7) Discuss Next Meeting

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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, Bylaws, and Rules of Procedure are followed in conducting NERC business.

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.

BAC SAR DT Kick-off Meeting

Chicago, IL

October 16 & 17, 2007

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Topics

- Support & References
- Overview of Process
- SC's Expectations of DT Members
  - Responsibilities
  - Products
    - SAR
    - Comment Form
    - Response to Comments
    - Recommendation to Standards Committee (SC)
  - Preservation of 'Open' Process
  - Addressing FERC Directives
- Questions

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

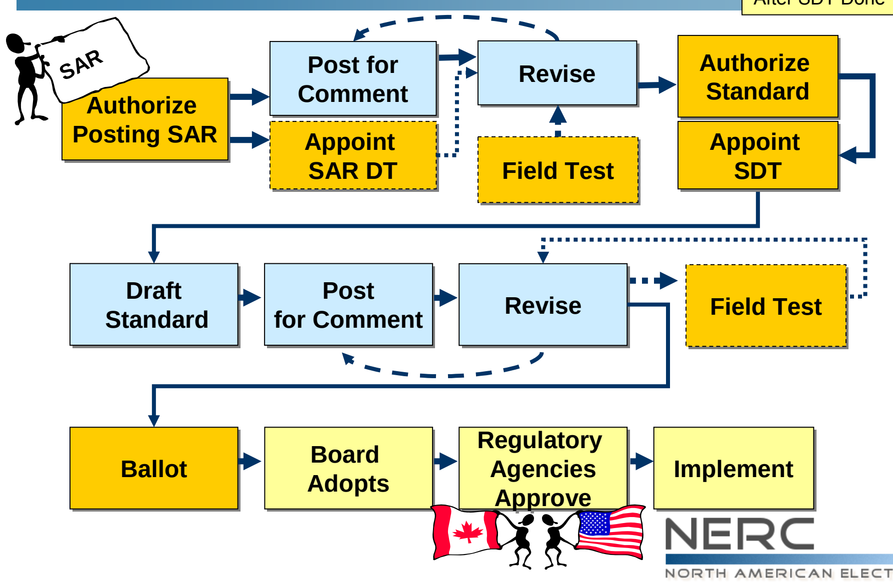
Support & Resources

- Reliability Standards Development Procedure Manual
- Drafting Team Guidelines
- SAR DT Scope Document
- Functional Model
- NERC Staff Directly Involved with Standards

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

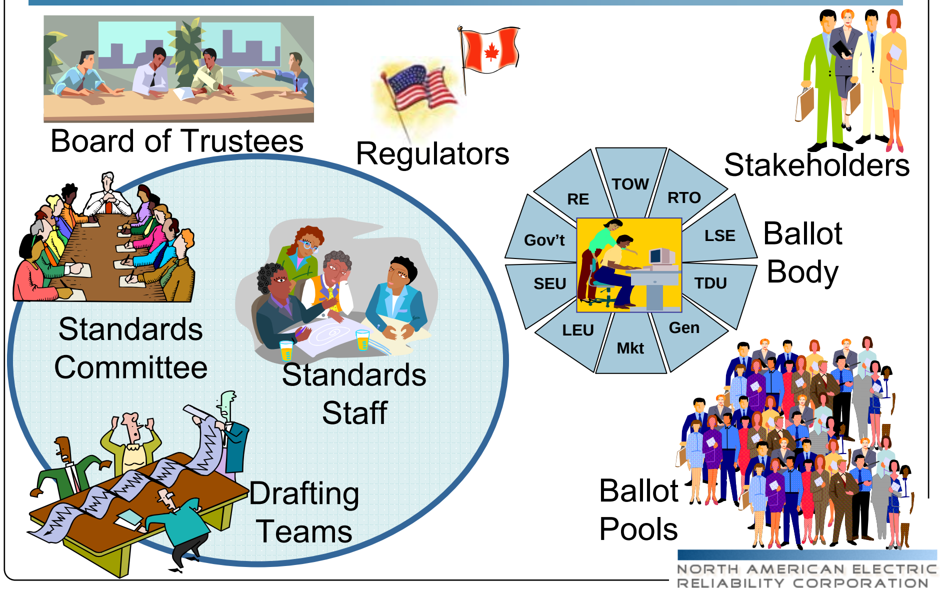
Overview of Process

Drafting Teams
SC Approval
After SDT Done



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Key Roles in Standards Process



NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Responsibilities of Chair

- Leads the Team in a neutral capacity
- Ensures the Team makes progress
- Conducts meetings of the Team
- Represents the Team to other bodies
- Reports progress to the SC

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Responsibilities of all Members

- Provide knowledge and expertise
- Participate actively
- Provide contributions, drafts, comments
- Attend meetings
- Participate in industry forums
- Provide feedback on standards development activities

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Responsibilities of Coordinator

- Advises the Team in a neutral capacity
- Monitors, facilitates, reports on, ensures active progress
- Prepares and circulates Team documents
- Maintains membership records
- Prepares for and assists at meetings

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

SAR DT Products

- SAR – clean and red line
- Comment form
- Consideration of Comments Report
- Recommendation to SC

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

- Establishes **purpose (reliability-related), scope and applicability** of proposed standard action
  - Keep revising until you have consensus on **purpose (reliability-related), scope, applicability**
- Can be used to add, modify or retire standards
- Requester 'owns' SAR and has final say until SAR is finalized

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form

- Ask very pointed questions
- If you've made changes, ask for feedback
- Ask for agreement on:
  - **Purpose** (reliability-related need for SAR)
  - **Scope**
  - **Applicability**
- Ask for known Regional Variances
- Ask if Business Practices are needed

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments Report

- Scan for 'sense' of stakeholders' reactions
- Consider & respond to **every** comment
  - Responses must be respectful
  - Responses should provide a justification for making/not making the requested change
- Develop 'summary consideration' for each question
- Add overview (cover page) of changes made – including issues resolved and those unresolved
- Make conforming changes to SAR

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

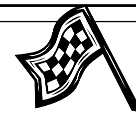
If the suggestion is submitted by	And the suggestion . . .	Then . . .	Ask stakeholders to . . .
Multiple entities in multiple regions	Does / may have technical merit	Incorporate suggestion	Confirm change
	Does not have obvious technical merits	Tell why suggestion lacks technical merit	
Single entity or by multiple entities in a single region	Does / may have technical merit	If widespread support anticipated, incorporate suggestion	Confirm change
		If widespread support not anticipated, don't incorporate	Indicate preference for suggestion
	Does not have obvious technical merits	Tell why suggestion lacks technical merit	

Weighing Comments

# signatures	# companies	# segments	# comments
1	1	1	1
5	1	1	1
8	1	3	3
12	12	1	12
12	3	3	??

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Ready to Post?



- SAR complete – clean and red-line?
- Consideration of comments complete?
- Consideration of comments matches SAR?
- Comment form complete?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Sample Question & Summary Consideration

1. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   Summary Consideration: Most commenters indicated they do believe there is a reliability-related need to upgrade the requirements in this set of standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Sample Responses:

- The drafting team agrees
- The applicability section was expanded to add the Transmission Operator and Load Serving Entity as proposed.

- The drafting team disagrees
- The change was not adopted because the Balancing Authority, not the Generator Owner, is responsible for calculating ACE.

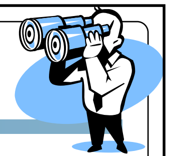
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Is SAR Ready for Standards Committee (SC)?

- Is there consensus amongst commenters on:
  - Reliability-related need
  - Scope
  - Applicability
- Submit all documents to SC for review & recommendation
  - Move forward to standard drafting
  - Withdraw

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Preserving the ‘Open’ Process



- ‘Standards under Development’ web site used for posting documents intended for stakeholder review and comment
  - Drafts of SARs
  - Reference Documents
  - Comment Forms
  - Response to Comments
- ‘Related Files’ section of each drafting team used for posting documents intended for use by team
  - Agendas and meeting notes (at least 5 days before/no more than 5 days after meeting)
- Meeting notices are posted on the ‘Meetings’ site
  - Anyone who registers may attend a meeting
  - Chair can limit guest participation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Addressing FERC Directives in Order 693

- ERO must comply with directives
- Two types of directives
  - FERC ‘directives to modify’ a standard
  - FERC ‘directives to consider’ comments submitted to FERC
- If unsure of directive, request clarification from FERC through coordinator
- FERC may submit comments
- FERC may participate in teams as observers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

FERC Directives Summary

- BAL-002-0 Disturbance Control Performance
  - Use NERC, not NERC OC
  - Substitute Regional Entity for Regional Reliability Organization
  - Include Demand-Side Management as Resource
  - Include Continent-wide Contingency Reserve Policy
  - Address concerns with not having enough contingency reserves
  - Define significant deviation and reportable event
  - Include frequency response requirement
  - Measures should be available in real-time to Balancing Authorities

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

FERC Directives Summary

- BAL-003-0 Frequency Response & Bias
  - Include levels of non-compliance
  - Determine appropriate periodicity of frequency response surveys
  - Define necessary amount of frequency response need for reliable operation for each Balancing Authority

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

FERC Directives Summary

- BAL-004-0 Time Error Correction
  - Include levels of non-compliance and additional measures for R3
  - In five-year review cycle, perform research that would provide technical basis for present or any alternative approach that is more effective and helps reduce inadvertent interchange.

FERC Directives Summary

- BAL-005-0 Automatic Generation Control
  - Develop process to calculate minimum regulating reserve for a Balancing Authority
  - Change title to be neutral
  - If regulation is being provided overn0n-ifrm transmission service, entity receiving regulation must have back-up plan to include loss of non-firm transmission service
  - Address Xcel and FirstEnergy comments when *standard* is revisited
  - Include measure that provides for verification process over required automatic generation control or regulating reserves a Balancing Authority maintains

FERC Directives Summary

- BAL-006-1 Inadvertent Interchange
  - Add measures concerning accumulation of large inadvertent interchange balances and levels of non-compliance
  - Examine WECC time error correction procedure as possible guide

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Questions?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

The Balancing Authority Controls SAR requesters thank all commenters who submitted comments on the first draft of SAR. This SAR was posted for a 30-day public comment period from July 3 through August 1, 2007. The requesters asked stakeholders to provide feedback on the standard through a special SAR Comment Form. There were 18 sets of comments, including comments from 61 different people from more than 3 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending .

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Balancing_Authority_Controls_Project_2007-05.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Anita Lee (G1)	AESO		✓								
2.	Tim Hattaway (G5)	Alabama Electric Coop., Inc.				✓						
3.	Ken Goldsmith (G2)	ALTW										✓
4.	Gerald Beckerle (G5)	Ameren	✓									
5.	Jeffrey V. Hackman	Ameren	✓									
6.	Thad K. Ness	American Electric Power (AEP)	✓				✓	✓				
7.	John Neagle (G5)	Associated Electric Coop., Inc.	✓									
8.	Dave Rudolph (G2)	BEPC										✓
9.	Robert Thomasson (G5)	Big Rivers Electric Corp.	✓									
10.	Brent Kingsford (G1)	CAISO		✓								
11.	Greg Rowland	Duke Energy	✓		✓							
12.	Howard F. Illian	Energy Mark, Inc.								✓		
13.	Ken Parker (G5)	Entegra Power Group					✓					
14.	Jerry Stout	Entergy Services, Inc.						✓				
15.	Jim Case (G5)	Entergy Services, Inc.	✓									
16.	Will Franklin	Entergy Services, Inc.										
17.	Steve Myers (I)(G1)	ERCOT		✓								
18.	Dave Folk	FirstEnergy Corp.	✓		✓		✓	✓				
19.	Guy Quintin	Hydro-Québec TransÉnergie	✓									
20.	Roger Champagne	Hydro-Québec TransÉnergie	✓									
21.	Ron Falsetti (I)(G1)	IESO		✓								
22.	Charles Yeung (G1)	IRC Standards Review Committee		✓								
23.	Kathleen Goodman	ISO New England		✓								
24.	Matt Goldberg (G1)	ISO-NE		✓								
25.	Michael Gammon	Kansas City Power & Light	✓									
26.	Eric Ruskamp (G2)	LES										✓
27.	Craig McLean	Manitoba Hydro	✓		✓		✓	✓				
28.	Tom Mielnik (G2)	MEC										✓

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
29.	Robert Coish (G2)	MHEB										✓
30.	Michael Brytowski (G2)	Midwest Reliability Organization (MRO)										✓
31.	Jason Marshall (G2)	MISO										✓
32.	Terry Bilke (G2)	MISO										✓
33.	William Phillips (G1)	MISO		✓								
34.	Carol Gerou (G2)	MP										✓
35.	Larry Brusseau (G2)	MRO										✓
36.	Jim Castle (G1)	NYISO		✓								
37.	Alicia Daugherty (G1)	PJM		✓								
38.	Stan Williams (G5)	PJM		✓								
39.	Brett Koelsch (G5)	Progress Energy Carolinas	✓									
40.	C. Robert Moseley (G4)	PSC of South Carolina									✓	
41.	David A. Wright (G4)	PSC of South Carolina									✓	
42.	Elizabeth B. Fleming (G4)	PSC of South Carolina									✓	
43.	G. O'Neal Hamilton (G4)	PSC of South Carolina									✓	
44.	John E. Howard (G4)	PSC of South Carolina									✓	
45.	Mignon L. Clyburn (G4)	PSC of South Carolina									✓	
46.	Phil Riley (G4)	PSC of South Carolina									✓	
47.	Randy Mitchell (G4)	PSC of South Carolina									✓	
48.	Jacquie Smith	ReliabilityFirst Corp.										✓
49.	Jim Griffith (G5)	SERC	✓									
50.	Carter Edge (G5)	SERC Reliability Corp.										✓
51.	John Troha (G5)	SERC Reliability Corp.										✓
52.	Pat Huntley (G5)	SERC Reliability Corp.										✓
53.	Mike Oatts (G5)	Southern Co. Services, Inc.	✓									
54.	Raymond Vice (G5)	Southern Co. Services, Inc.	✓									
55.	Jim Busbin (G3) (G5)	Southern Company - Transmission	✓									
56.	J. T. Wood (G3)	Southern Company Services	✓									
57.	Marc Butts (G3) (G5)	Southern Company Services	✓									
58.	Roman Carter (G3) (G5)	Southern Company Services	✓									
59.	Jim Haigh (G2)	WAPA										✓
60.	Neal Balu (G2)	WPS										✓
61.	Pam Oreschnick (G2)	XCEL										✓

I — Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 — IRC Standards Review Committee (IRC)
G2 — MRO Members (MRO)
G3 — Southern Company Services, Inc. (SOCO)

G4 — Public Service Commission of South Carolina (PSC SC)
G5 — SERC OC Standards Review Group (Project 2007-05)

Index to Questions, Comments, and Responses

1. Do you agree that there is a reliability-related reason for the proposed standard action? If not, please explain in the comment area.

Summary Consideration:

Question #1			
Commenter	**Yes**	**No**	**Comment**
Ameren	☑		
Manitoba Hydro	☑		
Entergy	☑		
Energy Mark, Inc.	☑		
ERCOT	☑		
Hydro-Québec TransÉnergie	☑		
FirstEnergy Corp.	☑		
Kansas City Power & Light	☑		
SERC	☑		
AEP		☑	For BAL-004, BAL-005 and BAL-006, AEP believes that the Reliability-Related to Business Practice relationship has been well vetted through unified efforts of NERC and NAESB, which included large and small industry participants as well as respected industry subject matter experts. There is not a reliability need to re-examine these, and some requests to do so may be ill informed. As an example, FERC 693 expresses concern of "large" inadvertent energy interchange balances and levels of non-compliance. The body of work from the above referenced efforts support the conclusion that the existence of "large" inadvertent energy interchange balances is not necessarily a bad thing. In many cases, correctly responding BAs will accumulate inadvertent energy interchange by supporting the system frequency; this is what they are supposed to do. A BA should not be held to an artificial repayment timeline when the inadvertent energy accumulation was a result of their correct support of the interconnection. There is no reliability relationship with the accumulation of inadvertent energy; it is purely a market/business practice/equity issue. The Standard referenced timing deadlines, already in place to agree and settle, are a somewhat effective criteria for recognition of the overall accumulation of inadvertent energy and the need to identify and to prevent cause. The

Question #1			
Commenter	**Yes**	**No**	**Comment**
			standard business practice for financial disincentive of inadvertent energy accumulation belongs in accord with NAESB. From a reliability perspective AEP is more concerned about the actual magnitude/impact of inadvertent energy interchange on the Bulk Electric System as it occurs in real-time, along with the timely recognition and cause resolution. Instead of being overly concerned about the accumulation/payback of inadvertent energy interchange balances over time, the reliability focus for benefit to the Bulk Electric System would be more effective to measure and enforce reporting criteria for the identification, cause, real-time magnitude of impact, and resolution follow-up in a timely manner. Measures to force real-time inadvertent identification, prevention mechanisms/processes, and to report root cause for compliance assessment would be more appropriate tool for maintaining reliability in real-time and preventing detrimental impact on the Bulk Electric System, than worrying about settlement business practices. Then habitual non-compliance could be measured and addressed. With the independent nature of the entities involved in the NERC functional model, the BAs sometimes are not totally responsible for the impact on inadvertent energy accumulation. Various entities can have a meaningful impact on affecting inadvertent energy by their operational practices with very little recourse mechanism from the BAs to prevent the causes of inadvertent energy. AEP believes that the more appropriate fix to the inadvertent energy issue is to re-write portions of BAL-001 that would prompt proper control behavior.
Response:			
Duke Energy	☑		
IESO	☑		
IRC-SCR	☑		
ISO New England	☑		
MRO	☑		
PSC of SC	☑		
ReliabilityFirst Corp.	☑		
SOCO - Transmission	☑		

2. Do you agree with the scope of the proposed standard action? If not, please explain in the comment area.

Summary Consideration:

Question #2			
Commenter	**Yes**	**No**	**Comment**
Ameren	☑		
Manitoba Hydro	☑		
Entergy	☑		
Energy Mark, Inc.	☑		
ERCOT	☑		
Hydro-Québec TransÉnergie	☑		
FirstEnergy Corp.	☑		However, the scope should be expanded to include a review of any existing and pending Regional Reliability Organization/Regional Entity standards, policies, requirements, etc. that contain Balancing Authority Controls that enhance reliability and that can and should be elevated to one of the NERC Balancing Authority Control standards to eliminate duplication and address or eliminate fill-in-the-blank standards. This SAR should also include direction on ensuring that this standard deveopment recognizes and is consistent with the Markets that exist and are pending including the methods and concepts used by those markets to ensure reliability. In addition, this SAR should include direction on identifying and addressing issues, if any, associated with Balancing Authority Area size as it relates to Balancing Authority Controls.
Response:			
Kansas City Power & Light	☑		
SERC	☑		
AEP		☑	With respect to BAL-004, BAL-005 and BAL-006, the NERC SAR should only be looking at editing the existing language to better align them with the new NERC pro-forma.
Response:			
Duke Energy		☑	The scope of this SAR should be combined with the scope of the SAR for proposed standards BAL-007 thru BAL-011.
Response:			
IESO	☑		

Question #2			
Commenter	**Yes**	**No**	**Comment**
IRC-SCR	☑		
ISO New England	☑		
MRO	☑		
PSC of SC	☑		
ReliabilityFirst Corp.	☑		
SOCO - Transmission	☑		

3. Do you agree with the applicability of the proposed standard action? If not, what function entities do you think need to be added or delete?

Summary Consideration:

Question #3			
Commenter	**Yes**	**No**	**Comment**
Ameren	☑		
Manitoba Hydro	☑		
Entergy		☑	Transmission Operator, and Load Serving Entity are listed in BAL-005 and should be marked as being applicable.
Response:			
Energy Mark, Inc.	☑		
ERCOT	☑		
Hydro-Québec TransÉnergie		☑	To be consistent with current BAL-005-0 Applicability, which is applicable to GOP, TOP and LSE, we should include TOP and LSE unless the Standards are rewritten to exclude TOP and LSE.
Response:			
FirstEnergy Corp.	☑		
Kansas City Power & Light	☑		
SERC	☑		
AEP	☑		
Duke Energy	☑		
IESO	☑		
IRC-SCR	☑		
ISO New England	☑		
MRO	☑		
PSC of SC	☑		
ReliabilityFirst Corp.	☑		

Question #3			
Commenter	**Yes**	**No**	**Comment**
SOCO - Transmission	☑		

4. If you are aware of any Regional Variances associated with the proposed standard action, please identify here.

Summary Consideration:

Question #4		
Commenter	**Regional Variance**	**Comment**
Ameren		No comment.
Manitoba Hydro		No comment.
Entergy		No comment.
Energy Mark, Inc.		No comment.
ERCOT		The team possibly should consider Bias Setting determination for single Balancing Authority, single Region Interconnections and whether that should constitute the need for a Regional Variance
Response:		
Hydro-Québec TransÉnergie		Québec Interconnection being a single BA interconnection: BAL-004 Requirements R2 to R4 would not apply; however, R1 objective would be respected. BAL-005 Requirements R7 should be modified by adding at the end: or control frequency in the case of a single Balancing Authorities operating asynchronously. BAL-006 Requirements are not required for reliability purpose but all the data are obtained for commercial purposes.
Response:		
FirstEnergy Corp.		Not aware of any Regional Variances beyond those already specified in the SAR.
Response:		
Kansas City Power & Light		The Western System has differences regarding time correction from the Eastern System and ERCOT.
Response:		
AEP		BAL-006 has regional vaiances for the MISO and SPP RTO footprints.
Response:		
IESO		None
IRC-SCR		WECC Automatic Time Error Correction, SPP II Acounting Waiver, MISO II Acounting Waiver, and the Eastern Interconnection restriction on fast time errors need to be considered during the drafting process.
Response:		
ISO New England		Single balancing area interconnections may need some special treatment in some aspects.

Question #4			
Commenter	**Regional Variance**		**Comment**
Response:			
MRO			N/A
PSC of SC			N/A
ReliabilityFirst Corp.			N/A
SOCO - Transmission			We are not aware of any Regional Variances associated with the proposed standard action.
Response:			

5. If you have any other comments on this SAR that have not already been provided, please provide them here.

Summary Consideration:

Question #5	
Commenter	**Comment**
Ameren	No comment.
Manitoba Hydro	No comment.
Entergy	The revised standards should be balloted separately so that the entire set is not rejected because of an issue with one of the standards, nor approved as a set with flaws/concerns in one or more of the standards. BAL-002: - Add VRFs - Several Requirements have no Measures (some are statements rather than requirements) (e.g. R1, R1.1, R2 - 2.6, R6-6.2). - Consider adding a frequency measure as component of recovery (i.e. an entity has a DCS event but Interconnect frequency remains/recovers to within "defined limits" as stated in the Purpose section. We are inclined to believe there should not be a penalty if frequency remains within "defined limits".) - Consider removing the first pargraph in the Levels of Non-Compliance section for requiring an entity to increase contingency reserves. It is not clear as to whether the increase in reserves is for a valid reliability reason or if it is intended to penalize the entity. Penalties are now assessed via the compliance program so if there is a need for increased reserves from a reliability standpoint, why is it only for one quarter, and why is offset by one month? - Revise the Levels of Non-compliance to meet the VSL format for project 2007-23. BAL-004: - Add VRFs - Several Requirements have no Measures (some are statements rather than requirements) - Consider removing time error correction altogether - is there a reliability need? - If there is a reliability need for time error correction, having to follow the NERC standard and NAESB standard is a setup for confusion and errors. An example - The NAESB standard states in step 7 that BAs will particpate using one of two methods:" Frequency offset… in accordance to the directives of the Interconnection Time Monitor"; the NERC standard states that "...BAs shall offset its frequency schedule by 0.02 HZ…" - Why does the comment regarding a "regional variance" for the EI to not initiate a fast time error correction between 04 and 11 CPT need support? The NAESB standard appears to already state that fast time corrections cannot occur during this period regardless of which interconnect. What is the goal of this requirement? Based on frequency response at 22:00 CPT it appears that there should be

Question #5	
Commenter	**Comment**
	a constraint on fast time error corrections around the on to off peak transition as well. - Does the NERC OC have a criteria for selecting the Interconnection Time Monitor? Is it voluntary as to whether a chosen RC accepts the responsibility, and is the Time Monitor chosen from a pool of volunteers? - The RC serving as the Interconnection Time Monitor does have responsibilities and should remain as an applicable entity. BAL-005 - Add VRFs - Add Measures - Agree with the suggestion to change the title of the standard - What revision will this process produce? There is already a Rev 1 approved by the BOT. - R1 - R1.3 needs to be more detailed as to what is actually desired. Stating that generation facitilities in an Interconnection must be included within the metered boundaries of a BA area is vague. Does this mean there must be metering on the generator itself? By default, aren't all generating facilities within some metered boundary of a BA? Likewise with Transmission and Load. - Define "adequate" in R3 - Define "adversely" in R7 - Should R7 state the goal is to maintain ACE rather than Net Scheduled Interchange? - Consider moving the requirements for ACE into BAL-001, as they seem to be more applicable to that standard than this one. - NAESB's special cases for ACE equations should be included here or in BAL-001, assuming ACE is a reliability parameter. BAL-006 - add VRFs - add Measures - R4 "business day" needs definition, this is a 24x7 industry - the RRO has obligations listed in the Compliance section, should RRO be added to the Applicability? - Some reference to the NAESB standard on inadvertent payback needs to be included
Response:	
Energy Mark, Inc.	1. The Disturbance Control Standard currently addresses recovery from sudden resource losses. Before this standard can be modified to address the inclusion of Demand Side Management as a resource to meet this standard, the reserve definitions currently used by NERC will need to be rewritten. This action will be required because some of the reserves are defined based on the specific resources that have traditionally used to supply those reserves. For example, Spinning Reserve currently includes the subcategory of Frequency Responsive Reserve. If the Frequency Response

Question #5	
Commenter	**Comment**
	Standard moves to implementation, then it will probably be necessary to define that reserve separately as was recommended by the NERC IOS ITF many years ago. In addition, if this standard is modified to include both loss of supply resources and loss of load, the the issue of holding reserves for reliability will need to be expanded to the holding of maneuvering margin for reliability. This change may require additional changes in the way we think about reserves and set up the system for operation. Finally, with respect to DCS, recent research has revealed that interconnection failure from an imbalance condition would most likely occur as the result of a precurssor frequency event (a large frequency excursion) and a concurrent sudden loss of generation or load event. It has also revealed that 9 of 10 large frequency excursions on the Eastern Interconnection and 8 of 10 large frequency excursions on the Western Interconnection (precussor events) are experienced without a disturbance. If DCS is intended to insure appropriate recovery from precussor events that could result in interconnection failure, the current standard that only requires action when there is a disturbance may not be addressing the correct events for maintaining interconnection reliability. 2. The Time Error Correction Standard scope is about right, but the results of the suggested research may result in changes in the scope. 3. The Automatic Generation Control standard have its name changed to address the primary issue that the standard addresses, the specific requirements for implementation of the ACE Equation. I recommend that the standard name be changed to ACE Equation Implementation. The standards currently fail to define two necessary conditions for maintaining interconnection reliability that are currently the basis for ACE Equation implementation. The first requriement for coordinated control on an interconnection is that all BAs control to the same scheduled frequency value. The second requirement is that all scheduled interchange sum to zero across the interconnection.(This is the balanced schedule requirement implemented in the interchange standards.) Both of these requirements should be stated clearly in the NERC Standards, and this standard is the place to do so. NERC took the direction a number of years ago of setting requirements for the BA to achieve with their implementation of Automatic Generation Control rather than how AGC should work. As a consequence, any requirements for specific amounts of Regulating Reserve would be addressed in other balancing standards. The holding and use of the correct amount of reserves including Regulating Reserves is currently measured by CPS1 and CPS2. Any other specification of minimum Regulating Reserve amounts would be redundant to these measures, and as a consequence could only increase the costs of holding reserves without providing necessary additional reliability. The primary reason for having this standard is to assure that the Balancing Authority Operator and the Reliability Coordinator are provided the necessary information about ACE and balancing to assure situationally awareness. 4. The Inadvertent Interchange Standard should have automatic inadvertent payback added to the list of options considered to address the issue of large inadvertent accounts.
Response:	

Question #5	
Commenter	**Comment**
ERCOT	Please clarify that the team should determine whether a Regional Standard will be required to support the continent-wide standard requirements regarding contingency reserves
Response:	
FirstEnergy Corp.	We suggest the following grammatical changes to improve clarity: Under Brief Description, in bullet item 1, the word "need" should be changed to "needed"; in bullet item 2, the phrase "comments receive" should be changed to "comments received"; and, in bullet item 9 the word "requirement" should be changed to "requirements." Under Detailed Description, the phrase "while also and" should be changed to the word "in" in the last sentence of the first paragraph. Under Attachment 1 the phrase "in considering these comments" in the first paragraph should be changed to "consider existing comments." Lastly, under BAL-002-0 bullet item 2 of Attachment 1, the bullet item should be revised to "Include requirement that explicitly provides for the use of Demand Side Management (DSM) as a resource for contingency reserves."
Response:	
Kansas City Power & Light	The scope is rather broad and does not go into any substantial detail for proposed changes. The scope does indicate industry comments included with the SAR will be given consideration for changes to the standards. To that end, here are some concerns regarding some of those comments: 1. Some of the suggestions are recommending to establish minimum reserve levels for purposes of regulation of load. Each Balancing Authority should be allowed to establish their own regulation reserves based on their unique load characteristics. As an example, the regulating reserves a Balancing Authority with a steel furnace load will be much different from a Balancing Authority with a less volatile load. The performance measures for adaquate regulating reserves are the Control Performance Standards and are a good measure of adaquate regulating reserves. There is no need to establish a minimum regulating reserve in the standards. 2. There are suggestions recommending to establish minimum reserve levels for the sudden loss of generation. Each Balancing Authority, Region and Reserve Sharing Group should be allowed to establish the levels of Contingency Reserves based on their unique operating characteristics. The performance measure for the sudden loss of generation already exists and is well established under the Disturbance Control Standard. Meeting this performance standard is the true measure of adaquate contingency reserve levels. There is no need to establish minimum contigency reserve in the standards. 3. There is a suggestion to include dispute resolution requirements to the standards. Reliability standards are to establish minimum operating criteria to maintain a reliable bulk electric system.

Question #5	
Commenter	**Comment**
	Dispute resolution processes are administrative in nature and have no place in reliabiltiy standards. Dispute resolution processes should be included in regional membership agreeements, interchange agreements, etc.
Response:	
SERC	The SERC OC Standards Review Group (Project 2007-05) submits the following comments on the Balancing Authority Controls SAR: BAL-002 - Disturbance Control Standard: We recommend that NERC define, either in the NERC Glossary or Section D1.4 - Additional Compliance Information, the following terms applicable to BAL-002 and identified in Requirements 4 and 6: (1) Reportable Disturbances (defined in NERC Glossary), (2) Disturbance Recovery Criterion, (3) Disturbance Recovery Period, (4) Contingency Reserve Restoration Period This action would eliminate the need for Requirements 4.1, 4.2, 6.1 and 6.2 in either option and also Section D1.4 if the definitions are removed from the Standard and included in the NERC Glossary. Three of the above terms are defined as non-measurable requirements and the fourth is defined in D1.4. Adopting one of the above recommended options would provide a common and consistent reference for definitions utilized in the BAL-002 Standard. BAL-004 - Time Error Correction We recommend the following action should be taken by the BAL-004 SAR Drafting Team: (1) Coordinate with NAESB to assure that there are no overlapping and / or redundant requirements regarding time error correction, (2) Consider eliminating time error corrections during market transitions (0600 CPT and 2200 CPT), and (3) Develop a modified version of the Western Automatic Time Error Correction (WATEC) process in response to FERC directives and industry comments for implementation in the Eastern Interconnection. This can be done under the Balancing Authority Controls (Project 2007-05) or as a separate SAR, if this is more efficient for NERC from a Project Management standpoint. BAL-005 - Automatic Generation Control We recommend that the FERC directive for development of minimum Regulating Reserve requirements in BAL-005-0 be consolidated with the directive to develop continent-wide contingency

Question #5	
Commenter	**Comment**
	reserve requirements in BAL-002-0 so that all reserve requirements are consolidated in a single easily accessible location, preferably BAL-002. All requirements concerning operating reserves should be contained in one Standard; spreading requirements over a variety of Standards creates confusion and ambiguity and adding requirements in any Standard to separate regulating and spinning reserves is too prescriptive. Order 693 under BAL-002 suggests "Include a continent-wide contingency reserve policy, which should include uniform elements (definitions and requirements)", which supports this recommendation. We agree with NPCC that Supplemental Regulation may be provided by various and different types of Dynamic Transfers (including Pseudo Ties), as defined in the NERC Dynamic Transfer Reference Document. It does not appear, however, that this should be included in the Balancing Authority Controls (Project 2007-05) SAR, but passed on to the Balancing Authority Controls (Project 2007-05) Standard Drafting Team for consideration in the detailed crafting of the final standards. We support the following comment by First Energy, with additional clarification shown in brackets: "FirstEnergy states that Requirement R17 should include only “control center [frequency] devices” instead of devices at each substation. FirstEnergy states that accuracy at the substation level is unnecessary and the costs to install automatic generation control equipment at each substation would be high. FirstEnergy also states that the term “check” in Requirement R17 needs to be clarified. We recommend that the first sentence of Requirement 6 be deleted: "The Balancing Authority’s AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority’s ACE." This sentence attempts to informally describe the ACE equation. It is better to rely on BAL-001, Req. 1 to define the ACE equation in a more exact and thorough manner. We recommend that the BAL-005 Standard also include a requirement that states "The Balancing Authority shall include all Pseudo Ties in the calculation of Net Scheduled Interchange for the ACE equation, similar to Requirement 10, which ensures that Dynamic Schedules are included in the calculation of Net Scheduled Interchange for the ACE equation. We also offer these general comments on the BAL-005 SAR: (1) Measurements are missing from this standard. (2) If performance is measured against DCS and CPS criteria already included in other Standards, and members are penalized for non-compliance with those Standards, then isn't having Standard BAL-005-0 require how to achieve compliance too prescriptive? BAL-006-1 - Inadvertent Interchange Data We recommend that the FERC Order 693 suggestion to "Add measures concerning the accumulation of large inadvertent interchange balances and levels of non-compliance" should be coordinated with

Question #5	
Commenter	**Comment**
	NAESB. Accumulated balances are not a reliability issue. We note that references to Standards (i.e., Requirements, etc.) in the SAR Form are not consistent with the latest approved Standards.
Response:	
Duke Energy	Comments: The entire set of BAL standards should be addressed in unison, and the current piece-meal approach avoided. Currently there is a SAR for proposed standards BAL-007 thru BAL-011 as well as this SAR for BAL-002 thru BAL-006. A concept paper on balancing (ACE & frequency management, AGC, etc.) and the effect on reliability (system flows, frequency excursions, etc.) should be authored by a group of industry experts to reach a consensus on which issues are related to reliability. At a minimum, the concept paper should address concerns and issues brought forth previously by BAL-007 thru BAL-011 and concerns and issues identified by this SAR for BAL-002 thru BAL-006. This concept paper should be used to develop a comprehensive set of BAL standards that address the issues related to reliability.
Response:	
IESO	R1 in BAL-005 lacks clarity on measurability. How can a facility owner ensure that his facilities are included within the metered boundaries of a Balancing Authority Area? These requirements should be rewritten such that: A) There should be a requirement for facility owners to provide accurate metering data to BAs (measurable – contracts between facility owners and Metering Service Providers can act as a measure that this requirement is being satisfied); and B) A separate requirement for the BA to include these facilities in their metered boundary (It should be the BA as the responsible entity responsible for ensuring that all the facility owners are being metered and not the other way around as the current requirement seems to suggest.
Response:	
IRC-SCR	None
ISO New England	While I agree with the basic thrust of the SAR, I feel the need to re-emphasize important comments offered earlier, and also to provide additional comments on input that has been received from prior SARs and summarized in Attachment 1. (a) With respect to FERC Order 693 calling for DSM to provide contingency reserves within BAL-002, this should be achieved with comparability to the extent practical with generation resources, particularly as it relates to metering, testing, communications, and sustainability requirements. (b) FERC Order 693 with respect to BAL-002 discusses recognition of transmission losses, and it is noteworthy that the present standard refers to resource loss, which includes loss of transmission that deprives a Balancing Area of energy, causing a large negative ACE. For example, loss of

Question #5	
Commenter	**Comment**
	HydroQuebec imports into New England has been included in its DCS reporting for more than a decade. Also, it is not clear from the text whether requirements related to bottling of contingency reserve due to transmission limitations are being addressed by FERC, and further clarification seems necessary. Perhaps BAL-002 should be upgraded to state specifically that contingency reserve must be deliverable when locational concerns arise. (c) A BPL comment about BAL-002 calling for restoration of language concerning the Disturbance Recovery Period is correct and should be considered. (d) Existing BAL-002 requirement R3 discussed the need for reviewing First Contingency Losses at least annually. It should be noted that events such as changing equipment status on a transmission path (e.g., only 1 line remains in service to deliver energy from more than one generator) could necessitate review on a daily or even more frequent basis. (e) With respect to BAL-004, the regional variance for the Eastern Interconnection to not initiate a time error correction at 59.98 Hz between 0400 and 1100 Central Prevailing Time needs to be refined. "Initiated" should be replaced with "in use" or "implemented". If one does not want to accept some difficult to quantify increase in risk during the morning pickup by running at 59.98 Hz, what difference does it make if it was initiated before 0400 and retained, or if it was initiated afer 0400? Once the frequency schedule is in place, the laws of probability and risk and the physics of the situation "don't care" when it began. This comment should not only be carried forward to the SAR, but, this hole in the process should be fixed right now with a clarification to the Interconnection Time Error Monitor. We believe the intent was to avoid 59.98 Hz during the morning pickup, not to avoid its initiation during that period. Unfortunately, the ultimate technical writing that is in place has misconstrued the original intent, and a specific case has been observed in which a 59.98 Hz schedule continued to be used after 0400. We question whether the Interconnection Time Monitor has the tools, skills, or authority to distinguish between acceptable and unacceptable interconnection risks for each upcoming day. (f) With respect to BAL-005, FERC discusses the development of a calculation for determining a regulating requirement as a function of load, generation and interchange variations expected. Another factor that can impact this is how efficiently generators not providing AGC are moved along to match the generation requirement. For example, a manual process deployed hourly will probably cause a far greater need for regulation than an electronic dispatch the moves non-AGC generation along by sending out new desired dispatch points every 5 minutes. Also, there is a significant time of day impact to consider. Perhaps a process that allows requirements to be reduced on an hourly basis based on meeting standards within that hour of day is needed. As metrics such as CPS1 and CPS 2 monitor the successful deployment of regulating reserves continuously, perhaps regulation reserve

Question #5	
Commenter	**Comment**
	compliance should in effect be based on control performance as opposed to computed values. (g) With respect to FERC's interest in verifying that sufficient regulating resources are deployed per BAL-005, having more regulating resources during very light load periods can actually be a detriment to reliability, as low regulating limits are often greater than low operating limits, resulting in even more over-generation than would result if a resource was simply at its low operating limit. These conditions should be covered within compliance monitoring strategies. (h) With respect to First Energy's suggestion that all generation above a certain size be required to provide AGC in BAL-005, certain generation types such as nuclear, tire burners, trash burners, wind generation, some hydros, and some atypical generation facilities would be impractical to provide AGC. (i) In BAL-005 comments, BPL-PBL correctly asks for a clear defnition of what "becoming a burden on the interconnection" means with respect to providing or receiving supplemental regulation service. (j) Within BAL-005, there is still a need to re-iterate NPCC's concerns about pseudo-ties and supplemental regulation: prohibiting pseudo-ties for supplemental regulation is without technical basis, overly prescriptive, and would incur needless conversion costs. (k) Within BAL-005 requirement R7, it states that maintaining tie line schedules should be performed manually when AGC equipment becomes inoperable. A change may be desirable for single Balancing Area interconnections to allow for maintaining frequency manually instead. (l) Within BAL-006, there is a need to re-iterate NPCC's concerns about deploying automatic time error correction using primary inadvertent as per the WECC. Before the Eastern Interconnection adopts a similar strategy, it needs to reach a consensus on why it should be done.
Response:	
MRO	1. For BAL-002-0 ("Disturbance Control Standard"), the FERC Order 693 includes a definition of a significant frequency deviation and reportable event taking into all events that have an impact on frequency. (see FERC Order 693, paragraph 355) 2. For BAL-002-0 ("Disturbance Control Standard"), shouldn't the terms in section 1.4("Additional Compliance Information") be moved to the NERC glossary? These terms are "Reportable Disturbances", "Simultaneous Contingencies", "Multiple Contingencies within the reportable disturbance period", and "Multiple Contingencies within the Contingency Reserve Restoration Period". 3. The MRO supports the addition of Violation Severity Levels so as to comply with the current approved Standard form. 4. Would the Regional Entities be released from their requirement of submitting a monthly

Question #5	
Commenter	**Comment**
	Inadvertent report to NERC, if the requirement is added that all entities that are required to report Inadvertent Interchange through the NERC inadvertant reporting application? 5. Note: The Violation Severity Level methodology is currently out for comment and has not been approved. I would be premature to assign Violation Severity Levels to these standards until the SAR vor Violation Severity Levels has ben approved by the industry.
Response:	
PSC of SC	See other attachment for grammatical / typographical suggestions.
Response:	
ReliabilityFirst Corp.	N/A
SOCO - Transmission	Southern Company Transmission supports the comments submitted by Mr. Jim Griffith on behalf of the SERC Operating Committee.
Response:	

Balancing Authority Controls SAR
Summary of Stakeholder Comments

There were 18 sets of comments, including comments from 61 different people from more than 3 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages. The following table summarizes the comments received:

Question	Response Statistics	Common Comments	SAR Team Comments
1. Do you agree that there is a reliability-related reason for the proposed standard action?	Yes: 17/18 (0 with comment) No:1/18 (1 with comment)	No 1: Expressed concern with the re-examination of the reliability-related (NERC) to business practice (NAESB) relationship, specifically timing details that are already in place; suggests re-writing portions of BAL-001 to address inadvertent energy issue	
2. Do you agree with the proposed scope of the proposed standard action?	Yes: 16/18 (1 with comment) No: 2/18 (2 with comment)	Yes 1: Scope should be expanded to review existing and pending standards, policies requirement that contain BAC that enhance reliability to eliminate duplication and address of eliminate fill in the blank No 1: SAR should only include editing existing language to better align with new NERC pro-forma No 2: SAR should be combined with BAL-007 thru BAL-011	
3. Do you agree with the applicability of the proposed standard action?	Yes: 16/18 (0 with comment) No: 2/18 (2 with comment)	No 1 & 2: TOP and LSE are listed in BAL-005 but not marked as applicable	
4. Identify any Regional Variances	6 comments	1 & 6: consider bias setting determination for single BA, single region interconnections and whether that constitutes a regional variations 2: Quebec Interconnection as single BA interconnection	

Question	Response Statistics	Common Comments	SAR Team Comments
		3 & 5: Western System has differences for time error correction 4 & 5: BAL-006 MISO and SPP regional differences 5: Consider Eastern Interconnection restriction of fast time errors	

General Responses

Question 5 General Responses	Comment	SAR Team Discussion
Common	Entire set of BAL standards should be addressed together (these plus BAL-007 thru BAL-011) – Entergy & Duke Concept paper on balancing and effect on reliability should be authored by group of industry experts to reach consensus on issues related to reliability - Duke	
Grammar/Spelling	Under Brief Description, in bullet item 1, the word "need" should be changed to "needed" (2 comments); in bullet item 2, the phrase "comments receive" should be changed to "comments received" (2 comments); and, in bullet item 9 the word "requirement" should be changed to "requirements." (2 comments) – FirstEnergy Under Detailed Description, the phrase "while also and" should be changed to the word "in" in the last sentence of the first paragraph – FirstEnergy; Detailed Description: while also (some additional words appear to be needed) and Attachment 2 Under Attachment 1 the phrase "in considering these comments" in the first paragraph should be changed to "consider existing comments." – FirstEnergy Attachment 1 Intro Paragraph: In addition to working collaboratively with NAESB to confirm the "location" of currently overlapping requirements in the NERC standards and NAESB business practices, the standard drafting team will assist the stakeholders in considering these comments in determining	

Question 5 General Responses	Comment	SAR Team Discussion
	the changes to make to the standards, including directives from FERC Order 693, regional fillin-the-blank team comments, Version 0 (V0) industry comments, Violation Risk Factor comments, and SAR modifications that were posted for comments. Page 10: BPL-PBL — To properly communicate the purpose of this complex standard to those who are unfamiliar with this subject, it is necessary to first discuss "what we are trying to accomplish" before stating "how we will (to) accomplish it through use of ACE and Regulating Reserves". This can be achieved by reversing the order of the two sentences in this paragraph and rewording them such that they flow appropriately. Page 10: BPL-PBL — The three sentences of this requirement are actually three separate requirements that will require separate measures for compliance. Therefore, we ask that they be split into (three??) two separate requirements. Page 13: ISO-NE, NPCC, IMO — Levels of Non-Compliance — These are missing and need(s) to be added in Standard simultaneously.	

BAL-002-0 Disturbance Control

Question 5 **Other Responses about BAL-002 Disturbance Control**	**Comment**	**SAR Team Discussion**
VRFs	Add VRFs - Entergy	
Measures	Add measures - Entergy	
Levels of Compliance	Consider removing first paragraph in Levels of Compliance - Entergy Revise Levels of non-compliance to meet VSL format for project 2007-23 - Entergy Shouldn't "additional compliance information" be moved to NERC glossary? MRO	
Definitions	Consider adding frequency measure as recovery component - Entergy Before adding Demand Side Management as a resource, reserve definitions need to be rewritten – Energy Mark Define reportable disturbances, disturbance recovery criterion, disturbance recovery period, contingency reserve restoration period (this eliminates need for R4.1, 4.2, 6.1, and 6.2) - SERC If standard includes loss of supply resources and loss of load, then holding reserves needs to be expanded – Energy Mark If DCS is intended to insure appropriate recovery for precursor events, stand that only requires action when there is disturbance many note be addressing correct events for maintaining reliability – Energy Mark See FERC Order 693, paragraph 355 for	

Question 5 Other Responses about BAL-002 Disturbance Control	Comment	SAR Team Discussion
	definition of significant frequency deviation - MRO	
DSM	For DSM to provide contingency reserves – there needs to be comparable to the extent practical with generation resources (metering, testing, communications, and sustainability requirements) – ISO New England Bullet item 2 should be revised to "Include requirement that explicitly provides for the use of Demand Side Management (DSM) as a resource for contingency reserves."	
Contingency Reserves	No need to establish minimum contingency reserves –Kansas City Power & Light Consider including statement that contingency reserve must be deliverable when locational concerns arise – ISO New England	
R3	Events could necessitate review of First Contingency Losses more frequently than annually (daily or even more frequent) – ISO New England	
Regional Standard	Are regional entities released from requirement of submitting monthly Inadvertent report to NERC if requirement is added that all entities are required to report Inadvertent Interchange through NERC inadvertent reporting application? MRO -0Team should determine whether regional standard will be required to support continent-wide standard requirements regarding contingency reserves - ERCOT	

Question 5 **Other Responses about BAL-002 Disturbance Control**	**Comment**	**SAR Team Discussion**
Re-iteration of existing comments	Consider BPL comment call for restoration of language concerning the Disturbance Recovery Period – ISO New England	

BAL-004-0 Time Error Correction

Question 5 Other Responses on BAL-004-0 Time Error Correction	Comment	SAR Team Discussion
VRFs	Add VRFs – Entery	
Measures	Add measures - Entergy	
NAESB	Consider removing time error correction altogether (2) – eliminate confusion between NERC and NAESB documents – Entergy and NAESB standard includes regional variance for EI to not initiate fast time error correction between 04 and 11 CPT – Entergy and SERC Coordinate with NAESB to eliminate overlap and redundancy - SERC	
Interconnection Time Monitor	Does NERC have criteria for selection Interconnection Time Monitor - Entergy RC should remain applicable entity for Interconnection Time Monitor - Entergy Does the Interconnection Time Monitor have the tools, skills, or authority to distinguish between acceptable and unacceptable interconnection risks –ISO New England	
Scope	Results of research may result in changes in scope – Energy Mark Develop modified version of Western Automatic Time Error Correction (WATEC) process in response to FERC directive - SERC	
Regional Variation	Refine regional variation for Eastern Interconnection to not initiate time error	

Question 5 Other Responses on BAL-004-0 Time Error Correction	Comment	SAR Team Discussion
	correction needs to be refined: “initiated should be replaced with “in use” or “implemented – ISO New England	

BAL-005-0 Automatic Generation Control

Question 5 Other Responses on BAL-005-0 Automatic Generation Control	Comment	SAR Team Discussion
Title/Version	Change title – Entergy & Energy Mark What revision will this effort produce - Entergy	
VRFs	Add VRFs - Entergy	
Measures	Add measures (2) – Entergy & SERC	
Scope	Consider moving requirements for ACE into BAL-001 - Entergy NAESB's special cases for ACE equations should be included here or in BAL-001 – Entergy Current standard fails to define two necessary conditions for maintaining interconnection reliability – coordinated control on interconnect that all Bas control to same scheduled frequency value and all scheduled interchange sum to zero across intercommunion – both should be in standard – Energy Mark No need to establish minimum regulating reserve – Kansas City Power & Light Recommend FERC directive to develop minimum regulating reserve requirements in BAL-005 be consolidated with directive to develop continent-wide contingency reserve requirements in BAL-002 - SERC Include requirement that states "BA shall include all Pseudo Ties in calculation…" - SERC If performance is measured against DCS	

Question 5 Other Responses on BAL-005-0 Automatic Generation Control	Comment	SAR Team Discussion
	and CPS criteria included in others standards and members are penalized for non-compliance, then isn't having BAL-005 that requires how to achieve compliance too prescriptive - SERC Consider a process that allows regulating requirements to be reduced on hourly basis based on meeting standards within hour of day – ISO New England Consider regulating reserve should be in effect based on control performance, not computed values – ISO New England	
R1	R1 – R1.3 – Need more details - Entergy R1 lacks clarity on measurability; re-write requirements such that there is a requirement for facility owners to provide accurate metering data and provide separate requirement for BA to include these facilities in their metered boundary – IESO	
R3	R3 – Define adequate - Entergy	
R6	Remove first sentence of R6 – R1 equation is more exact - SERC	
R7	R7 – define adversely - Entergy R7 – Should the be to maintain ACE rather than Net Scheduled Interchange - Entergy R7 – consider changing for single BA interconnection to allow for manual frequency control – ISO New England	
R17	Clarify R17 – SERC (supporting First Energy comment)	

Question 5 Other Responses on BAL-005-0 Automatic Generation Control	Comment	SAR Team Discussion
Compliance Monitoring	Having more regulating resources during light load periods can be a detriment to reliability – these conditions should be covered within compliance monitoring strategies – ISO New England	
Re-iteration of existing comments	Agree with NPCC that supplemental regulation may be provided by different types of Dynamic Transfers – should not be included in SAR but addressed by standard - SERC FirstEnergy's suggestion that all generation be required to provide AGC would be impractical – ISO New England BPL-PBL correctly asks for clear definition of what "becoming a burden on the interconnection" means – ISO New England Support NPCC's concerns about pseudo-ties and supplemental regulation – overly prescriptive and would incur needless conversion costs – ISO New England	

BAL-006-1 Inadvertent Interchange

Question 5 Other Responses on BAL-006 Inadvertent Interchange Data	Comment	SAR Team Discussion
VRFs	Add VRFs - Entergy	
Measures	Add measures - Entergy	
Applicability	Should RRO be added to Applicability Section since RRO has obligations in Compliance section – Entergy	
NAESB	Reference to NAESB standard on inadvertent payback needs to be included - Entergy Coordinate FERC directive to add measures concerning accumulation of large inadvertent interchange balances and levels of non-compliance with NAESB; accumulated balances are not a reliability-related issue - SERC	
R4	R4 – define business day - Entergy	
Large Inadvertent Accounts	Have automatic inadvertent payback added to list of options considered to address issue of large inadvertent accounts – Energy Mark	
Dispute Resolution	Dispute resolution should not be included in standards- Kansas City Power & Light	
Re-iteration of existing comments	Support NPCC's concern about deploying automatic timer error correction using primary inadvertent, as per WECC – ISO New England	

Standard Authorization Request Form

Title of Proposed Standard	Balancing Authority Controls (Project 2007-05)
Request Date	June 20, 2007

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Resources Subcommittee	☐	New Standard
Primary Contact Terry Bilke	☒	Revision to existing Standards – see list below: BAL-002 - Disturbance Control Performance BAL-004 – Time Error Correction BAL-005 – Automatic Generation Control BAL-006 Inadvertent Interchange
Telephone 317.249.5463 Fax 317.249.5994	☒	Withdrawal of existing Standard
E-mail tbilke@midwestiso.org	☐	

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

The purpose of this set of four standards is to ensure that Balancing Authorities take actions to maintain interconnection frequency with each Balancing Authority contributing its fair share to frequency control and without burdening transmission facilities with excessive imbalances of load and generation.

This SAR is intended to address the following:

- FERC Final Rule "Mandatory Reliability Standards for the Bulk-Power System, FERC Order 693" on the NERC standards BAL-002, 004, 005, and 006
- To specify the Time Error Correction, special Area Control Error cases, and Inadvertent Interchange reliability requirements/business practices with NERC and NAESB collaborative participation
- To incorporate the necessary content, structure, and language to comply with the NERC standards process

This SAR expands on the work already underway with the BAL-004, 005, 006 SARs, by requiring that BAL-002, 004, 005, and 006 be upgraded in accordance with the NERC Reliability Standards Development Plan 2007- 2009.

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

The four standards in this set are all Version 0 standards (BAL-006-1 was revised, effective on May 1, 2006, to add SPP to the standard's regional difference). As the ERO begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to start-up the ERO and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation and any subsequent standards development that have implications to the BAL standards.

In addition, the Resources Subcommittee believes there is sufficient electric power industry interest to review, re-evaluate, specify, expand, and determine the proper location of each reliability requirement and business practice associated the following NERC Standards and NAESB business practices:

- Time error correction (NERC BAL-004 and NAESB WEQBPS — 004-000)
- Automatic Generation Control and ACE equation special cases (NERC BAL-005 and NAESB WEQBPS — 003-000)
- Inadvertent interchange (NERC BAL-006 and NAESB WEQBPS — 005-000).

The drafting team will review all of the requirements in the existing standards and make a determination with stakeholders on whether to:

- Modify the requirements to improve clarity and measurability, while removing ambiguity
- Move the requirement (into another SAR or Standard or to the certification process or standards)
- Eliminate the requirement (either because it is redundant or because it does not support bulk power reliability)

Supporting Documents:

- NAESB WEQ Manual Time Error Correction Standards - WEQBPS-004-000: Copyright c 1996-2005 NAESB, Reproduced with NAESB's Permission
- NAESB WEQ Area Control Error (ACE) Equation Special Cases Standards - WEQBPS-003-000: Copyright c 1996-2005 NAESB, Reproduced with NAESB's Permission
- NAESB WEQ Inadvertent Interchange Payback Standards - WEQBPS-005-000: Copyright 1996-2005 NAESB, Reproduced with NAESB's Permission

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 standard drafting team will:

- Work collaboratively with NAESB to ensure that the elements of these standards that are need to support reliability are include in the revised standard
- Consider comments receive during the initial development of this set of standards and other comments received from ERO regulatory authorities and stakeholders
- Bring the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Rules of Procedures

The standard drafting team will review all of the requirements in the following set of standards:

- BAL-002 – Disturbance Control Standard
- BAL-004 – Time Error Correction
- BAL-005 – Automatic Generation Control
- BAL-006 – Inadvertent Interchange

For each existing requirement, the standard drafting team will also work with NAESB and stakeholders to:

- Eliminate redundancy (or overlap) in the requirements and associated business practices
- Identify requirement that should be moved into other SARs, standards, or business practices
- Eliminate requirements that do not support bulk power reliability
- Improve clarity of, improve measurability of, and remove ambiguity from the remaining requirements

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

The standard drafting team will, working cooperatively with NAESB and representatives of the Compliance Program, address the comments from stakeholders and directives from FERC identified in Attachment 1 (relative to the following standards) while also bringing the requirements and compliance elements into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Sanctions Guidelines while also and Attachment 2:

- BAL-002 – Disturbance Control Standard
- BAL-004 – Time Error Correction
- BAL-005 – Automatic Generation Control
- BAL-006 – Inadvertent Interchange

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	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.
☒	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.
☒	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.
☐	Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
☐	Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
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
BAL-002-0	Revision
BAL-004-0	Revision
BAL-005-0	Revision
BAL-006-1	Revision

Related SARs

SAR ID	Explanation
BAL-004-2	Individual SAR withdrawn by this SAR
BAL-005-2	Individual SAR withdrawn by this SAR
BAL-006-2	Individual SAR withdrawn by this SAR
BAL-003	Addresses management of schedule changes, management of ACE during curtailments, and definition of some of the components of ACE (frequency bias)
Frequency Response SAR	Addresses the relationship between reserves and frequency response

Regional Differences

Region	Explanation
Eastern Interconnection	BAL-004-1, Eastern Interconnection shall not initiate a manual “fast time” time error correction between the hours 0400 – 1100 Central Prevailing Time
SPP	BAL-006-1, Inadvertent Interchange accounting waiver approved by the Operating Committee on May 1, 2007
MISO RTO	BAL-006-1, Inadvertent Interchange accounting Waiver approved by the Operating Committee on March 25, 2004

Attachment 1 – Comments and Directives to Address in Revising BAL-002, BAL-004, BAL-005 and BAL-006

In addition to working collaboratively with NAESB to confirm the "location" of currently overlapping requirements in the NERC Standards and NAESB business practice, the standard drafting team will assist the stakeholders in considering these comments in determining the changes to make to the standards, including directives from FERC Order 693, regional fill-in-the-blank team comments, Version 0 (V0) industry comments, Violation Risk Factor comments, and SAR modification that were posted for comments.

BAL-002-0 Disturbance Control Standard

FERC Order 693

- Modify to make requirements R4.2 and R6.2 refer to NERC rather than the NERC Operating Committee
- Include requirement that explicitly provides that Demand Side Management (DSM) may be used as a resource for contingency reserves
- Include a continent-wide contingency reserve policy, which should include uniform elements (definitions and requirements)
- Recognizes the loss of transmission as well as generation, thereby providing a realistic simulation of possible events that might affect the contingency reserves

Regional Fill-in-the-Blank Team Comments

- Modify R2 to remove reference to "sub-Regional Reliability Organization or Reserve Sharing Group"
- Determine what elements of contingency reserve should be included in North American standard and what elements should be included in regional standard

VO Industry Comments

- Modify Requirements:
    - BPL – PBL - Though they are technically correct, the first two sentences of the first paragraph are located in the wrong section of this standard. Since they refer to which disturbances must be reported on for compliance purposes, they belong in the Compliance Monitoring Process section of this standard.
    - NPPD - R2 - The requirement should state a minimum performance level that must be met by the reserve levels and mix of Operating Reserve - Spinning and Operating Reserve - Supplemental.
    - NPPD - R3 - There appear to be two requirements here. First the requirement to deploy contingency reserves. Second the requirement to review the amount of reserves to be carried. They should be split. There is no measurement included for review of the contingencies on an annual basis and there should be.
    - BPL – PBL - An important part of this requirement that is missing from what is written here is that the specified recovery MUST occur within the Disturbance Recovery Period; which is presently specified as 15 minutes. Rectify this by adding "within the Disturbance Recovery Period" to the end of the first sentence of this requirement.
- Modify Compliance Elements:
    - NPPD - Reset Period - The reset period should be one calendar quarter without a violation on a reportable disturbance.
    - FRCC - The Levels of Non-compliance are not really levels of non-compliance. These are what a BA or RSG must do if they do not meet the DCS, so really appear

to be sanctions or penalties associated with non-compliance. This should be reviewed and corrected.

Violation Risk Factor Comments

- None

BAL-004-0 Time Error Correction

FERC Order 693

- Include levels of non-compliance (now replaced by violation severity levels) and additional measures for requirement R3
- Perform research that would provide technical basis for present or any alternative approach that is more effective and helps reduce inadvertent interchange, in five-year review cycle of standard

VO Industry Comments

- None

Violation Risk Factor Comments

- None

SAR Modification Posted for Comments Considerations

- Consider all options for time error including: automatic time error correction for all interconnections; using a smaller frequency offset for a longer period of time; increase the time error correction trigger values and initiate an all day 24 hour correction.
- Support regional variance for Eastern Interconnection to NOT initiate a manual “fast time” time error correction between 0400 hours and 1100 hours Central Prevailing Time
- Limit applicability to the Balancing Authority
- Address time error correction settlement methodology
- Define any new terms used in the revised standard

BAL-005-0 Automatic Generation Control

FERC Order 693

- Develop process to calculate minimum regulating reserve for Balancing Authority, taking into account expected load and generation variation and transactions being ramped in and out
- Change title to be neutral as to source of regulating reserves and allows inclusion of technically qualified DSM
- Clarify requirement R5 to specify the requirement type of transmission or backup plans when receiving regulation from outside the Balancing Authority when using nonfirm service
- Include measure that provides for verification process over required automatic generation control or regulating reserves Balancing Authority maintains
- Consider comments submitted by Excel:
  - Xcel requests that the Commission reconsider Requirement R17 of this Reliability Standard stating that the accuracy ratings for older equipment (current and potential transformers) may be difficult to determine and may require the costly replacement of this older equipment on combustion turbines and older units while adding little benefit to reliability. Xcel states that the Commission should clarify that Requirement R17 need only apply to interchange metering of the balancing area in those cases

where errors in generating metering are captured in the imbalance responsibility calculation of the balancing area.

- Consider comments submitted by FirstEnergy:
  - o FirstEnergy suggests that a single entity should have the responsibility to establish, through an annual review process, the level of regulating reserves that a balancing authority must maintain pursuant to the control performance standard requirements.
  - o FirstEnergy suggests that all generators and technically qualified DSM that participate in energy markets should install automatic generation control as a condition of market participation. In non-market areas, FirstEnergy suggests that balancing authorities could meet requirements through bilateral contracts or the normal scheduling process and suggests that the Commission might have to assert its jurisdiction and order technically qualified DSM providers to install automatic generation control at their facilities. FirstEnergy states that further work would need to be conducted on the technical qualifications and capacity thresholds that would control whether installation of automatic generation control would be required.
  - o FirstEnergy states that Requirement R17 should include only “control center devices” instead of devices at each substation. FirstEnergy states that accuracy at the substation level is unnecessary and the costs to install automatic generation control equipment at each substation would be high. FirstEnergy also states that the term “check” in Requirement R17 needs to be clarified.

VO Industry Comments

- Purpose statement
  - o BPL-PBL - To properly communicate the purpose of this complex standard to those who are unfamiliar with this subject, it is necessary to first discuss "what we are trying to accomplish" before stating "how we will to accomplish it through use of ACE and Regulating Reserves". This can be achieved by reverseing the order of the two sentences in this paragraph and rewording them such that they flow appropriately.
- Re-order and re-work requirements
  - o BPL-PBL - Placing the requirements in this standard in the order that they appeared in the NERC Policies has resulted in them being in a confusing and seemingly random order. Calrity of this standard would be improved immensely if these many requirements were to be reordered in more of a building block approach; beginning with the most fundamental and working toward the most complex. A suggestion would be to put them in the order of R1, R6 - R8, R13 - R16, R9 - R12, R2, R3, R4, R5.
  - o BPL-PBL - The three sentences of this requirement are actually three separate requirements that will require separate measures for compliance. Therefore, we ask that they be split into two separate requirements.
  - o BPL-PBL - The phrase "shall sample data" is not specific enough about "what data" as to enable this requirement to be measurable. If possible, please list specifically what data or types of data are meant. If existing policy is not specific enough in this area to be able to do this as a part of Version 0 then, we ask that this issue be forwarded to the appropriate Version 1 Drafting Team for resolution.
  - o BPL-PBL - The two sentences of this requirement are actually two separate requirements that will require separate measures for compliance. Therefore, we ask that they be split into two separate requirements.
  - o BPL-PBL - The words "prevent such service from becoming a burden upon …" are not sufficiently definitive enough to enable this requirement to be measurable. Since existing policy

does not give any further guidance in this area, we ask that this issue be forwarded to the appropriate Version 1 Drafting Team for resolution.

- Non-compliance is missing:
  - ISO-NE, NPCC, IMO - Levels of Non-Compliance - These are missing and needs to be added in Standard simultaneously.

Violation Risk Factor Comments

- R12 – sub-requirements should be separate requirements
- R12.3 – redundant
- R14 – check for redundancy of second statement. This seems to be a real-time requirement, not planning. Is this for archival data requirements?

SAR Modification Posted for Comments Considerations

- Work cooperatively with NAESB to consider all supplemental regulation service, overlap regulation service, pseudo ties, and dynamic schedule options and then revise the appropriate reliability requirements and business practices.
- Limit applicability to just the Balancing Authority.
- Recommend developing a reference to support the ACE calculation.
- Consider the following comments and suggestions from NPCC members:
  - In R2.4, replace "its ties and schedules" with "the ties and schedules of the receiving Balancing Authority". Do we wish to say Balancing Area instead?
  - NPCC participating members have indicated that it is improper to restrict supplemental regulation service to dynamic scheduling. For example, the NPCC ACE Diversity Interchange (ADI) project uses pseudo-ties successfully. In such an arrangement, the signed expected value of supplemental service received is 0 for an hour, however, it can and will differ and is not particularly predictable. Please change this here and in all other places to give pseudo-ties equal status with dynamic schedules for supplemental regulation. It is inconsistent to allow pseudo-ties for moving load and generation, which can have fairly predictable values and should be e-tagged for use in IDC. The NPCC ADI project, using pseudo-ties, was reviewed and approved by the NERC SAR Drafting Team prior to its implementation, its results have been shared with the NERC SAR Drafting Team, has been problem-free, and has served as useful input into the MISO ADI project and the prospective WECC ADI project. Prohibiting pseudo-ties for supplemental regulation is without technical basis, overly prescriptive, and would incur needless conversion costs.
  - In R3.2.4, NIs is used in 2 places with 2 definitions, and it should be clarified if loads and generation in these equations are all positive values (or not).
  - In R3.2.5, NIa is used in 2 places with 2 definitions, and it should be clarified if loads and generation in these equations are all positive values (or not). Also, the use of pseudo-ties should be added to allow for supplemental regulation.
  - R2.3.6 needs to be revamped, merely stating that ACE = 0 for overlap regulation.
  - Does the "may" in R3.3.3 need to be changed to "shall"?
  - How does one enforce or validate the 99.95% reliability criterion of R3.5?
  - Measure M1's wording is very tedious.

Current Approved Interpretation

- Incorporate approved Interpretation BAL-005-1, Requirement 17

BAL-006-1 Inadvertent Interchange

FERC Order 693

- Add measures concerning the accumulation of large inadvertent interchange balances and levels of non-compliance
- Examine WECC time error correction procedure as a possible guide
- Modify the regional differences (now regional variances) so they reference the current Reliability Standards and are in the standard form, which includes Requirements, Measures and Levels of Non-Compliance (now Violation Severity Levels)
- Explore FirstEnergy's request to define function of waiver in reliability standard development process

VO Industry Comments

- Purpose/requirement contradiction
  - BPA - R1-R5 - These requirements correctly describe how to calculate Inadvertent Interchange. However, they fail to actually address the stated purposes of the standard, which are to ensure that both "reliability is not compromised by inadvertent flows" and "Balancing Authorities do not excessively depend upon (others) ". Please either modify the purpose to reflect the requirements or add requirements that address the purposes as stated.
- Split requirements
  - BPL-PBL - The two sentences of this requirement are actually two separate requirements that will require separate measures for compliance. Therefore, we ask that they be split into two separate requirements.
- Wording in R4
  - CAISO - R4 - In the last paragraph, the term "non-reliability considerations" is going to be impossible to define in this context. After-the-fact changes that are made between consenting BAs do not affect the interconnection.

  - IMO, NPCC, NYPA - Remove the wording "with like values but opposite signs" in order to make more clarity in R4.
- Requirements mixed in Compliance
  - NPPD - Compliance Monitoring - The Compliance Monitoring Process contains requirements. The level of non-compliace refers to the requirements in the Compliance Monitoring Process instead of the requirements.
  - BPL-PBL - The section 1G1.1 of the Compliance Monitoring Process talks specifically about a requirement for the BA to do AIEs to submit data to NERC for analysis purposes. Since AIE is not a part of the NERC Compliance Program at this time, this section should be moved to in the Requirements section of this standard.
- Non-compliance missing
  - NPPD - Levels of Non Compliance - The only non-compliance is related to providing a report and does not support the purpose "to ensure that, over the long term, the BALANCING AUTHORITY AREAS do not excessively depend on other BALANCING AUTHORITY AREAS in the INTERCONNECTION for meeting their demand or INTERCHANGE obligations."

Violation Risk Factor Comments

- None

SAR Modification Posted for Comments Considerations

- Consider payback options including, but not limited to, unilateral inadvertent interchange payback, bilateral inadvertent interchange payback, financial inadvertent interchange settlement, and automatic time error correction
- Add clarifying language to the regional variances to address MISO and SPP's use of "scheduling agents;" or add inadvertent interchange requirements to eliminate regional differences for MISO, SPP, and other ISOs/RTOs use of "scheduling agents"

- Add inadvertent interchange dispute resolution requirements, including adding requirements to provide data to identify and resolve disputes about interchange quantities
- Add requirements to use NERC designated electronic application for inadvertent interchange accounting
- Consider the following comments and suggestions from NPCC members:
    - In R1, the phrase “for any jointly owned generating units or remote load” should be dropped from the NIa and Nis definitions. Supplemental regulation should be included in either term.
    - R1.4 and R1.5 have redundancy in referring to the NERC OC designated electronic tool.
    - In R.2, it is not clear what hourly adjustments are, but it seems like a replacement for the end of the month meter correction presently performed when one reads the strikeout language.
    - In R2.4, replace intermediate with intermediary.
    - R2.5 and R2.6 are changing the present rules (currently, Balancing Authorities give their data to their regional representative by the 15th, who then cross-checks and resolves differences by the 22nd when it is forwarded to NERC via entry into the SPP Inadvertent Tool). The due date has been changed by one day to the 21st. It is not clear what benefit there is to decreasing the process by one day, and, re-education and changing of business processes are required (small tweaks, it is true) to support it.
    - All objections to ATEC in BAL-004-1 apply here, and are not repeated for brevity.
    - R7 needs some additional work. Bilateral payback is a method to reduce accumulated inadvertent, and it is not a type of accumulated energy. Given the extreme difficulty in doing sufficient bilateral payback to keep inadvertent levels at low values, it is impractical to suggest that all past accumulated energy will be paid back bilaterally.
    - R1.1.6’s first sentence should replace the phrase “removed from” with “removed from and added to”. Also, it is suggested that its final sentence be modified to read: “The net of these “settlement” schedules equal zero in the absence of scheduling errors”.
    - R1.1.7 refers to a seemingly non-existent section F.

Attachment 2: Reliability Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance

In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

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 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

This is a requirement that, if violated, could directly 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 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 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 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.

itigation Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment —** follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels must be applied for each requirement and may be combined to cover multiple requirements, as long as it is clear which requirements are included and that all requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: more than 95% but less than 100% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: more than 85% but less than or equal to 95% compliant.

- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: more than 70% but less than or equal to 85% compliant.
- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: 70% or less compliant.

Compliance Monitor

Replace, 'Regional Reliability Organization' with 'Regional Entity'

Fill-in-the-blank Requirements

Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

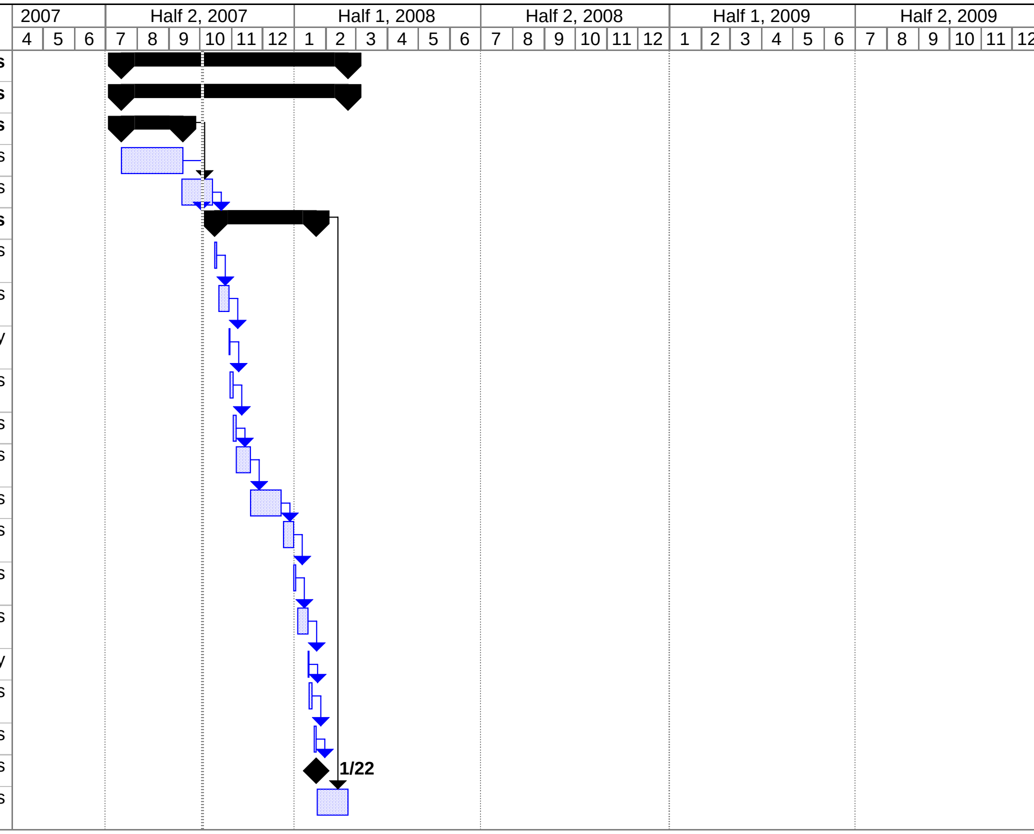
Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

ID	Task Name	Duration
1	**NERC Standard Development for Project 2007-05**	**221 days**
2	**SAR Development and Finalization**	**221 days**
3	**Step 1 - Draft SAR**	**60 days**
4	Step 1b - Appoint SAR Drafting Team	60 days
5	Step 2a- Solicit Public Comment on SAR	30 days
6	**Step 2b - Address Comments & Revise SAR**	**99 days**
7	Conduct 1st Meeting to Respond to Comments and Revise SAR	2 days
8	Facilitator Produces Draft Documents & Sets Up Webex	10 days
9	Conduct Webex to Complete Response to Comments & Revise SAR	1 day
10	Facilitator Produces Final Draft Documents & Submits to NERC Staff	3 days
11	NERC Staff Edits Documents & Adds to SC Agenda	3 days
12	SC Authorizes Recommended Action - Posting SAR for 2nd Comment Period	14 days
13	Post 2nd Draft of SAR for 30-day Comment Period	30 days
14	Facilitator Assembles & Distributes Comments & Sets Up Second Meeting	10 days
15	Conduct 2nd Meeting to Respond to Comments & Revise SAR	2 days
16	Facilitator Produces Draft Documents & Sets Up Webex	10 days
17	Conduct Webex to Complete Response To Comments & R	1 day
18	Facilitator Produces Final Draft Documents & Submits to NERC Staff	3 days
19	NERC Staff Edits Documents & Adds to SC Agenda	2 days
20	SAR Complete	0 days
21	Step 3 - Authorization to Proceed to Standard Development	30 days



Project: Project 2007-05 Balancing Authority
Date: Wed 10/3/07

Task
Progress
Milestone
Summary
Rolled Up Task
Rolled Up Milestone
Rolled Up Progress
Split
External Tasks
Project Summary
Group By Summary