

Consideration of Comments on 7th Draft of Balance Resources and Demand Standards

The Balance Resources and Demand Standard Drafting Team thanks all commenters who submitted comments on the latest draft of the proposed Balance Resources and Demand Standards. These standards were posted for a 30-day public comment period from January 2 through January 31, 2007. The Balance Resources and Demand Standard Drafting Team asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 32 sets of comments, including comments from more than 85 different people from more than 50 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 that the Standards Committee authorize moving these standards forward to balloting.

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/Balance-Resources-Demand.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>.

Consideration of Comments on 7th Draft of Balance Resources and Demand Standards

Commenter		Organization	Industry Segment											
			1	2	3	4	5	6	7	8	9	10		
1.	Anita Lee	Alberta Electric System Operator		✓										
2.	Ken Goldsmith	Alliant Energy	✓											
3.	James F. Sorrels, Jr.	American Electric Power	✓					✓	✓					
4.	Jason Shaver	American Transmission Co. LLC												
5.	Lorissa Jones	Bonneville Power Administration	✓											
6.	Rich Ellison	Bonneville Power Authority												✓
7.	Bart McManus	Bonneville Power Administration	✓											
8.	Jamie Murphy	Bonneville Power Administration	✓											
9.	Tracy Edwards	Bonneville Power Administration	✓											
10.	Alan Gale	City of Tallahassee						✓						
11.	Paul Bleuss	CMRC												✓
12.	CJ Ingersoll	Constellation Energy Control and Dispatch			✓									
13.	Gerry Farringer	Consumers Energy Company			✓	✓	✓							
14.	Jeffrey W. DePriest	Detroit Edison			✓		✓							
15.	Doug Hils	Duke Energy	✓											
16.	Howard F. Illian	Energy Mark, Inc.										✓		
17.	Ed Davis	Entergy Services, Inc.	✓											
18.	William L. Franklin	Entergy Services, Inc.							✓					
19.	David Lemmons	Excel Energy Services							✓					
20.	David L. Folk	FirstEnergy Corp.	✓		✓		✓	✓						
21.	Don McInnis	Florida Power & Light Co.	✓		✓									
22.	Erick Senkowicz	Florida Reliability Coordinating Council		✓										
23.	Linda Campbell	Florida Reliability Coordinating Council		✓										
24.	Clint Burrow	GRE	✓											
25.	Roger Champagne	Hydro-Québec/TransÉnergie	✓											
26.	Ron Falsetti	Independent Electricity System Operator		✓										
27.	Brian Thumm	ITC Transmission	✓											
28.	Michael Gammon	Kansas City Power & Light Company	✓											
29.	Robert Coish (MRO)	Manitoba Hydro	✓		✓		✓	✓						
30.	Jason Marshall	Midwest ISO, Inc.		✓										
31.	Terry Bilke	Midwest ISO, Inc.		✓										
32.	Joseph Knight	Midwest Reliability Organization												
33.	Jim Haigh (WAPA)	Midwest Reliability Organization												✓
34.	Alan Boesch (NPPD)	Midwest Reliability Organization												✓

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Commenter		Organization	Industry Segment											
			1	2	3	4	5	6	7	8	9	10		
35.	Neal Balu (WPS)	Midwest Reliability Organization												✓
36.	Carol Gerou (MP)	Midwest Reliability Organization												✓
37.	Ken Goldsmith (ATT)	Midwest Reliability Organization												✓
38.	Tom Mielnik (MEC)	Midwest Reliability Organization												✓
39.	Pam Oreschnick (XEL)	Midwest Reliability Organization												✓
40.	Dick Pursley (GRE)	Midwest Reliability Organization												✓
41.	Dave Rudolph (BEPC)	Midwest Reliability Organization												✓
42.	Eric Ruskamp (LES)	Midwest Reliability Organization												✓
43.	Michael Calimano	New York ISO		✓										
44.	Joe Dobes	NIPSCO	✓											
45.	William SeDoris	Northern Indiana Public Service Co.			✓									
46.	Guy V. Zito (NPCC)	NPCC CP9 Reliability Standards Working Group												✓
47.	Ralph Rufrano (NYPA)	NPCC CP9 Reliability Standards Working Group	✓											
48.	Ed Thompson (ConEd)	NPCC CP9 Reliability Standards Working Group	✓											
49.	Ron Falsetti (IESO)	NPCC CP9 Reliability Standards Working Group		✓										
50.	Bill Shemley (ISO-NE)	NPCC CP9 Reliability Standards Working Group		✓										
51.	David Kiguel (Hydro One)	NPCC CP9 Reliability Standards Working Group	✓											
52.	Roger Champagne (HQTE)	NPCC CP9 Reliability Standards Working Group	✓											
53.	Kathleen Goodman (ISO-NE)	NPCC CP9 Reliability Standards Working Group		✓										
54.	Don Nelson (MAT&E)	NPCC CP9 Reliability Standards Working Group											✓	
55.	Greg Campoli (NYISO)	NPCC CP9 Reliability Standards Working Group		✓										
56.	Bob Pellegrini (United Illuminating)	NPCC CP9 Reliability Standards Working Group	✓											
57.	Jarad Barnhart (Nstar)	NPCC CP9 Reliability Standards Working Group	✓											
58.	Brian Hogue (NPCC)	NPCC CP9 Reliability Standards Working Group												✓
59.	Larry Larson	Otter Tail Power Company	✓											
60.	Verne Ingersoll	Progress Energy Carolinas	✓											
61.	Mignon L. Clyburn	Public Service Commission of SC											✓	
62.	Elizabeth B. Fleming	Public Service Commission of SC											✓	
63.	G. O'Neal Hamilton	Public Service Commission of SC											✓	

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Commenter		Organization	Industry Segment											
			1	2	3	4	5	6	7	8	9	10		
64.	John E. Howard	Public Service Commission of SC											✓	
65.	Randy Mitchell	Public Service Commission of SC											✓	
66.	C. Robert Moseley	Public Service Commission of SC											✓	
67.	David A. Wright	Public Service Commission of SC											✓	
68.	Phil Riley	Public Service Commission of SC											✓	
69.	Mike Gentry	Salt River Project												✓
70.	Mike Pfeister	Salt River Project	✓											
71.	Tom Abrams	Santee Cooper	✓		✓		✓						✓	
72.	Glenn Stephens	Santee Cooper												
73.	Wayne Ahl	Santee Cooper												
74.	Tom Botello	Southern California Edison												✓
75.	Marc Butts	Southern Company Services, Inc.	✓											
76.	Roman Carter	Southern Company Services, Inc.	✓											
77.	J.T. Woods	Southern Company Services, Inc.	✓											
78.	Raymond Vice	Southern Company Services, Inc.	✓											
79.	James Y. Busbin	Southern Company Transmission	✓		✓									
80.	Earl W. Shockley	Tennessee Valley Authority	✓											
81.	Larry Akens	Tennessee Valley Authority	✓											
82.	Edd Forsythe	Tennessee Valley Authority	✓											
83.	John Kell	Tennessee Valley Authority	✓											
84.	Howard Rulf	We Energies			✓	✓	✓							
85.	Nancy Bellows (WACM)	WECC Reliability Coordination Comments Work Group												✓
86.	Raymond Vojdani	Western Area Power Administration	✓											

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1. The drafting team modified the implementation plan so that it does not include retirement of BAL-002 — Disturbance Control Standard. Do you agree with this modification to the implementation plan? If not, please explain.

Summary Consideration: Most commenters indicated support of this change to the implementation plan.

Question #1			
Commenter	Yes	No	Comment
Western Area Power Administration			See question 6.
Response: Please see the response to your comments on question 6.			
Constellation Energy Control and Dispatch		<input checked="" type="checkbox"/>	As discussed in previously submitted comments there is a concern that there is the potential for a conflict between the BRD standards and BAL-002, and an entity could be placed in a situation where in order to be in compliance with one set of standards they would be forced to violate another. In addition, the elimination of the restrictions on the maximum assistance a BA provides to the Interconnection, i.e. their bias [See EOP-002-3, R5], while the BA with the contingency recovers, could result in excessive response to low frequency deviations.
Response: BAL-002 has been in effect during the field test without any obvious conflict. The drafting team does believe there are some redundancies. Regarding EOP-002-3, the new standard recognizes that good performance is supporting interconnection frequency – any excessive response will result in a frequency swing that may have an adverse impact on frequency. The RC has the responsibility to direct actions to protect the interconnection.			
MRO	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	The DCS standard may be redundant, but running BAL-002 in parallel will allow the industry to obtain experience and confidence in the new Standard before retiring the BAL-002 Standard. The MRO supports the idea of operating with both standards in parallel, provided that no double jeopardy is incurred if both standards would be violated during a single incident. The MRO recommends the drafting team propose a method for removing the risk of double jeopardy during the time that both standards would be enforced.
Response: The drafting team has no authority over compliance-related policies.			
Tennessee Valley Authority	<input checked="" type="checkbox"/>		We agree with BAL-002 being retained at this time as the field test did not address the potential reliability implications associated with eliminating the NERC Disturbance Control Standard (DCS). The DCS currently meets our expectations for minimizing the impact of a large generation loss on neighboring systems by required a 15-minute recovery period.

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Question #1			
Commenter	Yes	No	Comment
			We are not convinced that BAL-002 is needed in the long term, and would support the implementation of a field trial to gather information on the reliability implications of eliminating the DCS and operating only under CPM and BAAL, with the provision that the participating Balancing Authorities report their BAAL compliance information to the Resources Subcommittee for the events that would have been reportable under the DCS criteria. Based upon its analysis and review, the Resources Subcommittee could provide its recommendations to the Standards Committee on whether the data supports the development of a new SAR proposing the elimination of BAL-002 or the development of a more effective standard to replace BAL-002, addressing the transmission concerns that some parties have raised.
Response: The drafting team agrees that removal of BAL-002 can be field tested in the future.			
Detroit Edison	<input checked="" type="checkbox"/>		Detroit Edison supports maintaining the DCS compliance requirement while additional experience is gained and testing is performed under BAL- 007- 01
Response: Most commenters agreed with your position.			
ITC Transmission	<input checked="" type="checkbox"/>		BAL-002 should not be eliminated at this time. The reliability implications of switching from DCS to CPM/BAAL should be fully investigated before any further thought is given to eliminating DCS.
Response: Most commenters agreed with your position.			
Florida Reliability Coordinating Council	<input checked="" type="checkbox"/>		We thank the DT for addressing our concerns expressed in previous comments.
Response: The drafting team is following the standards development process – and making changes that are responsive to stakeholder comments is required under this process.			
Consumers Energy Company	<input checked="" type="checkbox"/>		After being involved in the BAAL field trial since September of 2005 it seems clear to me a direct frequency correlation is the way to proceed. We should support BAL-007 through BAL- 011. There seems to be a reluctance of many to replace BAL-002 (the DCS standard) I suspect this is due to many entities not being involved with the BAAL field trials. A transitional period of implementing BAL-007 through BAL-011 while maintaining BAL-002 would be agreeable. The BAAL field trial still had the DCS as a control requirement. A separate field trial suspending the BAL-002 standard would seem logical.
Response: The drafting team agrees that removal of BAL-002 can be field tested in the future.			
New York ISO	<input checked="" type="checkbox"/>		The NYISO appreciates the consideration to retain the requirements identified in BAL-002. However as noted in question #6 other items have not been fully

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Question #1			
Commenter	Yes	No	Comment
			addressed.
Response: Please see the drafting team's responses to your other comments.			
NPCC CP9 Reliability Standards Working Group	<input checked="" type="checkbox"/>		Necessary but not sufficient.
Response: Please see the drafting team's responses to your other comments.			
Energy Mark, Inc.	<input checked="" type="checkbox"/>		<p>BAAL was designed to replace and expand the requirements included in the current Disturbance Control Standard(DCS) and CPS2. Many still falsely believe that without a DCS the requirements for reserves will not be addressed in the standards. This is simply not true. Even without DCS, when a BA experiences a loss of generation, its CPS1 measure will change to a large negative value. If reserve is not retained to recover from generation disturbances, the BA will not be able to comply with the CPS1 standard due to the imbalance in its ACE. Therefore, with respect to Operating Reserve (10-15 minute reserve), CPS1 should still provide adequate compliance measurement. Ongoing research and forward thinking by many in the industry are directing the thought leaders to consider the need for a standard that would require delivery of Primary Governing Frequency Response and associated reserves to insure the delivery of this necessary resource.</p> <p>Those currently investigating this issue include the NERC RS, IEEE Task Force on Generator Governing Response and the WECC. Although the current DCS will no longer be required to insure reliability after the BAAL is implemented, the DCS will provide a nice placeholder and structure that can be easily modified to meet the requirements for a standard for Primary Governing Frequency Response and the reserves necessary to insure its delivery. I have come to the conclusion that it is not worth the effort to eliminate this standard at this time when it will probably be easier to just modify it in the future to meet the real reliability hole, the need for Primary Governing Frequency Response and associated reserves.</p>
Response: Your conclusions match those of the drafting team.			
Southern Company Transmission	<input checked="" type="checkbox"/>		Southern Company Transmission agrees that BAL-002 should not be retired. We support the modification to the implementation plan.
Response: Thank you for your support of these changes.			
Midwest ISO, Inc.	<input checked="" type="checkbox"/>		We agree with BAL-002 being retained at this time as the field test did not address the potential reliability implications associated with eliminating the NERC Disturbance Control Standard (DCS). The DCS currently meets our expectations for minimizing the impact of a large generation loss on neighboring systems by required a 15-minute recovery period, however we are concerned that retaining

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Question #1			
Commenter	Yes	No	Comment
			<p>BAL-002 puts the BA in the position that unforeseen consequences might lead a Balancing Authority to being non-compliant to both BAL-002 and BAL-007 attributed to a single event. We would suggest that the compliance aspects of the standards consider that an entity should not be penalized twice if both standards were violated for the same event.</p> <p>We are not convinced that BAL-002 is needed in the long term, and would support the implementation of a field trial to gather information on the reliability implications of eliminating the DCS and operating only under CPM and BAAL, with the provision that the participating Balancing Authorities report their BAAL compliance information to the Resources Subcommittee for the events that would have been reportable under the DCS criteria. Based upon its analysis and review, the Resources Subcommittee could provide its recommendations to the Standards Committee on whether the data supports the development of a new SAR proposing the elimination of BAL-002 or the development of a more effective standard to replace BAL-002, addressing the transmission-related concerns that some parties have raised.</p>
<p>Response: The drafting team has no authority over compliance-related policies. The drafting team agrees that removal of BAL-002 can be field tested in the future.</p>			
American Transmission Co.	<input checked="" type="checkbox"/>		<p>ATC agrees with the decision to retain BAL-002 standard.</p> <p>If BAL-002 is not being retired then what happens to IRO-005-2 requirements 4, 8, 9 and 11 which become effective upon the retirement of BAL-002? The four IRO-005-2 replacement requirements was balloted and approved. In other words the industry approved these four new requirements in addition to the decision to delete BAL-002. How will NERC reconcile these two decisions?</p>
<p>Response: While an 'initial ballot' was conducted, the ballot was never completed and the modifications to IRO-005-2 never received final approval. Note that the revised implementation plan does include revisions to IRO-005, but these revisions are limited to changing 'CPS' to 'CPM' and adding 'BAAL' to the list of limits addressed. References to the retirement of BAL-002 were removed.</p>			
ISO New England	<input checked="" type="checkbox"/>		Necessary but not sufficient.
<p>Response: Please see the drafting team's responses to your other comments.</p>			
Santee Cooper	<input checked="" type="checkbox"/>		We do agree with the retention of the Disturbance Control Standard for a yet to be determined period of time.
<p>Response: Most commenters agreed with the retention of DCS.</p>			

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Question #1			
Commenter	Yes	No	Comment
Florida Power & Light Co.	<input checked="" type="checkbox"/>		
WECC Reliability Coordination Comments Work Group	<input checked="" type="checkbox"/>		
Northern Indiana Public Service	<input checked="" type="checkbox"/>		
Entergy Services, Inc. (Transmission Owners)	<input checked="" type="checkbox"/>		
Entergy Services, Inc. (Generation & Mktg)	<input checked="" type="checkbox"/>		
FirstEnergy Corp.	<input checked="" type="checkbox"/>		
We Energies	<input checked="" type="checkbox"/>		
Kansas City Power & Light Company	<input checked="" type="checkbox"/>		
Salt River Project (Pfeister)	<input checked="" type="checkbox"/>		
Public Service Commission of SC	<input checked="" type="checkbox"/>		
Manitoba Hydro	<input checked="" type="checkbox"/>		
Hydro- Québec/TransÉnergie	<input checked="" type="checkbox"/>		
Independent Electricity System Operator	<input checked="" type="checkbox"/>		

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2. The drafting team modified the effective dates for the standard to align with the revised expected approval dates. Do you agree with the effective dates that appear in the revised implementation plan? If not, please explain.

Summary Consideration: Most stakeholders indicated support for the modified effective dates and the drafting team did not change these.

Question #2			
Commenter	Yes	No	Comment
Western Area Power Administration			See question 6.
Response: Please see the response to your comments on question 6.			
Alberta Electric System Operator		<input checked="" type="checkbox"/>	The proposed six month field test period for WECC members does not seem adequate to allow for proper assessment on the interconnections limits, particularly under disturbance situations. The WECC test period should be extended to a minimum of 12 months.
Response: Most stakeholders supported the proposed effective dates.			
Constellation Energy Control and Dispatch		<input checked="" type="checkbox"/>	<p>At this time with the implementation of mandatory standards, goals of uniformity and the uncertainty associated with penalties it is imprudent to implement a performance measure that is not applicable in all Interconnections. CECD operates in both the Eastern and Western Interconnections and, as a result, would be required to operate using two different performance measures simultaneously on the same EMS, resulting in additional cost and creating an unnecessary complication for operations personnel that can be eliminated with simultaneous implementation.</p> <p>In addition, CECD is concerned, based on initial BAAL calculations for BA operations in the West that the BAAL calculation will produce significantly different BAAL limits between the interconnections that are not technically justified. For example, a BA with a 20 MW bias and an actual frequency reading of 59.98 would have a BAAL limit of approximately 25 MW in the East but a 211 MW BAAL in the West. This indicates that there could be additional difficulties during field testing in the West that could lead to significant delays or an inability to implement the BAAL limits.</p>
Response: There are many WECC standards in place that are different from NERC standards, so Constellation Energy must already be in a situation where it must follow different sets of standards. The cost to implement reliability standards is not a factor for consideration – however the field trial did show that the cost to implement the new limits has been negligible.			

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Question #2			
Commenter	Yes	No	Comment
<p>There will be differences in BAALs for similar BAs in WI and EI – these differences are caused by the specific technical differences between the two interconnections – as such these are technically justified.</p>			
Kansas City Power & Light Company		<input checked="" type="checkbox"/>	<p>1. Do not agree with the principle that an entity can delay an "effective date" because they did not participate in field testing when field testing was available. The Eastern Interconnect, ERCOT, WECC and Hydro-Quebec should have the same effective date.</p> <p>2. Do not agree with replacing BAL-003 with BAL-010 for the following reasons:</p> <p>A. Does not include the treatment of Joint Owned Units in the calculation of Frequency Bias currently in BAL-003, R4.</p> <p>B. Does not include the treatment of Overlap Regulation Service and Supplemental Regulation Service in the calculation of Frequency Bias currently in BAL-003, R6.</p> <p>C. Does not require the use of Tie-Line Bias in Automatic Generation Control unless the use of TLB is adverse to reliability or the interconnect in currently in BAL-003, R3.</p> <p>3. Do not agree with retiring EOP-002-2, R5 with the implementation of the proposed standards as there is nothing in the proposed standards to prevent a Balancing Authority from overcorrecting when frequency is high or low in complying to operate within the proposed BAAL limits or Frequency limits.</p>
<p>Response:</p> <ol style="list-style-type: none"> Most commenters agreed with the revised effective dates, which include time to field test. Footnotes 1 and 2 which are included in BAL-010 require consideration of all loads and generation within the balancing authority area boundaries – this covers jointly owned units, overlap regulation service, and supplemental regulation service. The definition of ACE is tie line bias. Overcorrecting occurs today when Balancing Authorities move ACE towards zero to correct frequency deviations, even when moving ACE towards zero hurts frequency. The intent in eliminating EOP-002-2 R5 was to ensure that only those Balancing Authorities that are 'hurting' interconnection frequency, would make adjustments to correct for interconnection frequency. With the new software tools developed in support of the proposed standards, it is much easier for Reliability Coordinators to correctly identify those Balancing Authorities that are 'hurting' frequency and to direct just those Balancing Authorities to make adjustments. 			
Energy Mark, Inc.	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	I feel that the drafting team is exhausted and is attempting to complete the implementation of this standard as quickly as possible. I would have no problem

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Question #2			
Commenter	Yes	No	Comment
			with waiting until the Western Interconnection has reasonable opportunity to complete its field trial before balloting the new standard.
Response: Most stakeholders supported the proposed effective dates so they were not changed.			
Tennessee Valley Authority Midwest ISO, Inc.	<input checked="" type="checkbox"/>		We fully support that Balancing Authorities should be allowed to begin operating under the new BAL-007 as soon as they are capable - with proper notification to NERC for compliance monitoring purposes.
Response: Thank you for your support of the proposed effective dates.			
Southern Company Transmission	<input checked="" type="checkbox"/>		Southern Company Transmission supports the modification to the "effective dates" for the standard.
Response: Thank you for your support of the proposed effective dates.			
Florida Power & Light Co.	<input checked="" type="checkbox"/>		
Detroit Edison	<input checked="" type="checkbox"/>		
WECC Reliability Coordination Comments Work Group	<input checked="" type="checkbox"/>		
Northern Indiana Public Service	<input checked="" type="checkbox"/>		
Entergy Services, Inc. (Transmission Owners)	<input checked="" type="checkbox"/>		
Entergy Services, Inc. (Generation & Mktg)	<input checked="" type="checkbox"/>		
ITC Transmission	<input checked="" type="checkbox"/>		
FirstEnergy Corp.	<input checked="" type="checkbox"/>		
Florida Reliability Coordinating Council	<input checked="" type="checkbox"/>		
Consumers Energy Company	<input checked="" type="checkbox"/>		
New York ISO	<input checked="" type="checkbox"/>		
NPCC CP9 Reliability Standards Working Group	<input checked="" type="checkbox"/>		
We Energies	<input checked="" type="checkbox"/>		
Midwest ISO, Inc. (group)	<input checked="" type="checkbox"/>		
ISO New England	<input checked="" type="checkbox"/>		
Salt River Project	<input checked="" type="checkbox"/>		

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Question #2			
Commenter	Yes	No	Comment
(Pfeister)			
Public Service Commission of SC	<input checked="" type="checkbox"/>		
Manitoba Hydro	<input checked="" type="checkbox"/>		
Hydro-Québec/TransÉnergie	<input checked="" type="checkbox"/>		
Independent Electricity System Operator	<input checked="" type="checkbox"/>		
Santee Cooper	<input checked="" type="checkbox"/>		

3. The drafting team added a “mitigation time horizon” for each requirement. Do you agree with the mitigation time horizon for each requirement in the proposed standards? If not, please identify any requirement with a time horizon you feel is incorrect.

Summary Consideration: Many commenters indicated a lack of familiarity with ‘mitigation time horizons’. These were introduced in the ERO Rules of Procedure as one of the elements used to determine the size of a sanction. Requirements that must be mitigated in real-time operations would have a larger sanction than those that could be mitigated over a longer time period. The comment form provided a list of possible mitigation time horizons. The latest version of the Reliability Standards Development Procedure did not include mitigation time horizons – this was an omission in bringing the manual into conformance with the latest ERO Rules of Procedure and this omission should be corrected with the next revision to the manual. In the meantime, stakeholders will be asked to comment on and approve mitigation time horizons as they are developed with standards. The alternative is to have these time horizons identified outside the standard development process, and stakeholders indicated they wanted a voice in the selection of all the compliance elements within standards.

Most commenters agreed with the proposed mitigation time horizons.

Question #3			
Commenter	Agree	Do not agree	Comment
Western Area Power Administration			See question 6.
Response: Please see the response to your comments on question 6.			
MRO		<input checked="" type="checkbox"/>	<p>Mitigation Time Horizons are described near the top of this comment form.</p> <p>The description of the Mitigation Time Horizons states The ERO Rules of Procedure include the use of mitigation time horizons as one element used to determine the size of sanctions.</p> <p>Can the drafting team inform the Registered Ballot Body where the ERO definition of Mitigation Time Horizons can be found along with documentation describing how the mitigation time horizons will be used in determining penalties. Mitigation Time Horizons are not listed as a Performance Element of a Reliability Standard in the Reliability Standards Development Procedure Version 6 adopted by the NERC BOT on November 1, 2006. As such, it does not seem appropriate to include them in any Reliability Standards.</p> <p>The comment form description of Mitigation Time Horizons further</p>

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Question #3			
Commenter	Agree	Do not agree	Comment
			<p>states The drafting team used the following guidelines in developing mitigation time horizons for each requirement, whereas the final statement in the description of the Violation Risk Factors states The following categories of violation risk factors were approved with the latest version of the Reliability Standards Development Procedure. Like the Violation Risk Factors, the categories of Mitigation Time Horizons should also be approved and incorporated into the Reliability Standards Development Procedure in order to ensure that the definitions are consistent for all NERC Reliability Standards.</p> <p>The MRO cannot vote to approve a standard that includes Mitigation Time Horizons until the drafting team can produce ERO documented definitions and the documented manner in which the Mitigation Time Horizons will be used to determine penalties.</p>
<p>Response: Please see the summary consideration – the drafting team made a good faith effort to add mitigation time horizons to the standards in a manner that uses stakeholder comments and allows stakeholders to participate in the approval of the time horizons. There is a disconnect between the ERO Rules of Procedure and the latest version of the Reliability Standards Development Procedure – the next version of the Reliability Standards Development Procedure should include mitigation time horizons. Until then, mitigation time horizons are needed to determine the size of sanctions, and having the drafting teams develop these, and giving stakeholders the opportunity to comment on and ballot these with the standards, seems to be the best way of keeping the standards process moving forward in a manner that best supports the involvement of stakeholders.</p>			
Manitoba Hydro		<input checked="" type="checkbox"/>	<p>Manitoba Hydro endorses MRO comments: Mitigation Time Horizons are described near the top of this comment form. The description of the Mitigation Time Horizons states The ERO Rules of Procedure include the use of mitigation time horizons as one element used to determine the size of sanctions. Can the drafting team inform the Registered Ballot Body where the ERO definition of Mitigation Time Horizons can be found along with documentation describing how the mitigation time horizons will be used in determining penalties. Mitigation Time Horizons are not listed as a Performance Element of a Reliability Standard in the Reliability Standards Development Procedure Version 6 adopted by the NERC BOT on November 1, 2006. As such, it does not seem appropriate to include them in any Reliability Standards.</p> <p>The comment form description of Mitigation Time Horizons further</p>

Consideration of Comments on 7th Draft of Balance Resources and Demand Standards

Question #3			
Commenter	Agree	Do not agree	Comment
			<p>states The drafting team used the following guidelines in developing mitigation time horizons for each requirement, whereas the final statement in the description of the Violation Risk Factors states The following categories of violation risk factors were approved with the latest version of the Reliability Standards Development Procedure. Like the Violation Risk Factors, the categories of Mitigation Time Horizons should also be approved and incorporated into the Reliability Standards Development Procedure in order to ensure that the definitions are consistent for all NERC Reliability Standards.</p> <p>The MRO cannot vote to approve a standard that includes Mitigation Time Horizons until the drafting team can produce ERO documented definitions and the documented manner in which the Mitigation Time Horizons will be used to determine penalties.</p>
<p>Response: Please see the summary consideration – the drafting team made a good faith effort to add mitigation time horizons to the standards in a manner that uses stakeholder comments and allows stakeholders to participate in the approval of the time horizons. There is a disconnect between the ERO Rules of Procedure and the latest version of the Reliability Standards Development Procedure – the next version of the Reliability Standards Development Procedure should include mitigation time horizons. Until then, mitigation time horizons are needed to determine the size of sanctions, and having the drafting teams develop these, and giving stakeholders the opportunity to comment on and ballot these with the standards, seems to be the best way of keeping the standards process moving forward in a manner that best supports the involvement of stakeholders.</p>			
ITC Transmission		<input checked="" type="checkbox"/>	<p>There is insufficient material describing the development and use of mitigation time horizons for inclusion in the Reliability Standards. It is premature to include them in these version of the Standards. When the Reliability Standards Development Procedure is updated to include a detailed description of their meaning and usage, only then should they be included in a Reliability Standard.</p>
<p>Response: Please see the summary consideration - the time horizons are part of the ERO Rules of Procedure. The ERO Rules of Procedure were silent on who or when these would be developed. The time horizons are used as a factor to determine the size of sanctions. We expect that the next version of the Reliability Standards Development Procedure will include a description of the time horizons and will clarify that these will be developed by drafting teams and included with the standards as they are posted for comment and then balloted.</p>			
Florida Reliability Coordinating Council		<input checked="" type="checkbox"/>	<p>The "mitigation time horizons" are not part of the Reliability Standards Development Procedure, version 6.0, adopted by NERC BOT,</p>

Consideration of Comments on 7th Draft of Balance Resources and Demand Standards

Question #3			
Commenter	Agree	Do not agree	Comment
			<p>11/1/2006. As such it is not clear why these were included in this standard.</p> <p>We understand the description is provided in the comment form and the concept is included in the ERO Rules of Procedure, but we feel these horizons are part of a broader policy issue and since their use is not clearly stipulated in the NERC standards process, including them in the standards will cause unnecessary confusion to stakeholders and regulators.</p> <p>The mitigation time horizons should be clearly stipulated in the Reliability Standards Development Procedure prior to their use in any standard (from a policy perspective).</p>
<p>Response: Please see the summary consideration – the drafting team made a good faith effort to add mitigation time horizons to the standards in a manner that uses stakeholder comments and allows stakeholders to participate in the approval of the time horizons. There is a disconnect between the ERO Rules of Procedure and the latest version of the Reliability Standards Development Procedure – the next version of the Reliability Standards Development Procedure should include mitigation time horizons. Until then, mitigation time horizons are needed to determine the size of sanctions, and having the drafting teams develop these, and giving stakeholders the opportunity to comment on and ballot these with the standards, seems to be the best way of keeping the standards process moving forward in a manner that best supports the involvement of stakeholders.</p>			
Entergy Services, Inc. (Transmission Owners)		<input checked="" type="checkbox"/>	<p>The Mitigation Time Horizons for all of the requirements BAL-011-1 Frequency Limits R1, R2, R3, R4, R5, R6, and R7 should be REAL-TIME OPERATIONS. While the development of these limits sounds innocuous the values of those frequency limits actually implemented will affect real-time operational reliability of the Bulk-Power System, including the shedding of load.</p>
<p>Response: While the drafting team agrees that these requirements are very important, the requirements are not performed in real-time operations – and the drafting team agrees with most commenters that operations planning is the correct mitigation time horizon.</p>			
Energy Mark, Inc.		<input checked="" type="checkbox"/>	<p>The mitigation time horizon for the CPM is set at Operations Assessment. The problem is that the measure is looking at what is happening in the control room in real-time, but because of the high degree of variability in the measure, there is no way to judge the short term effect of individual decisions on reliability. The CPM measure, because it is statistical in nature is no less a measure of real-time</p>

Consideration of Comments on 7th Draft of Balance Resources and Demand Standards

Question #3			
Commenter	Agree	Do not agree	Comment
			operations than the BAAL measure. The problem is that, because it takes long periods of measurement to determine the true value of compliance, it has been relegated to a lower value measure. It should be included with other measures of real-time operations compliance with respect to its mitigation time horizon and put into the real-time operations or same-day category.
Response: While the drafting team agrees the parameter used is real time, the measures are assessed in the operations assessment horizon.			
Hydro-Québec/TransÉnergie ISO New England New York ISO NPCC CP9 Reliability Standards Working Group	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	For clarity, we suggest that mitigating time horizons and violation risk factors be specified for each requirement and sub-requirement. Some sub-requirements have mitigating time horizons and others do not.
Response: While the Violation Risk Factors drafting team did assign a Violation Risk Factor to each requirement and each sub-requirement, there were many comments received indicating that this was not necessary, If a requirement and all of its sub-requirements have the same Violation Risk Factor it is acceptable to place the risk factor on the requirement. The same philosophy can be applied to the mitigation time horizons.			
Independent Electricity System Operator	<input checked="" type="checkbox"/>		We agree with the Violation Risk Factors and the Mitigation Time Horizons assigned to the requirements in BAL-007 to BAL-010. However, it is unclear about those sub-requirements that do not have a VRF or MTH assigned to it. Could these be regarded as having the same VRF and MTH as those of the main requirements. Please clarify, preferably in the standards themselves for all readers. For example, BAL-008 Requirements, R1 is rated "Medium" and R1.3 is rated "Lower" - what about ratings for the other sub-requirements?
Response: While the Violation Risk Factors drafting team did assign a Violation Risk Factor to each requirement and each sub-requirement, there were many comments received indicating that this was not necessary, If a requirement and all of its sub-requirements have the same Violation Risk Factor it is acceptable to place the risk factor on the requirement. The same philosophy can be applied to the mitigation time horizons. The drafting team did not place violation risk factors or mitigation time horizons on all sub-requirements – just on those sub-requirements that have a different rating than the main requirement.			
Southern Company Transmission	<input checked="" type="checkbox"/>		Southern Company Transmission supports the inclusion of a "mitigation time horizon" for each requirement.
Response: The drafting team thanks you for your support.			

Consideration of Comments on 7th Draft of Balance Resources and Demand Standards

Question #3			
Commenter	Agree	Do not agree	Comment
Kansas City Power & Light Company	<input checked="" type="checkbox"/>		
Tennessee Valley Authority	<input checked="" type="checkbox"/>		
Detroit Edison	<input checked="" type="checkbox"/>		
WECC Reliability Coordination Comments Work Group	<input checked="" type="checkbox"/>		
Northern Indiana Public Service	<input checked="" type="checkbox"/>		
Constellation Energy Control and Dispatch	<input checked="" type="checkbox"/>		
FirstEnergy Corp.	<input checked="" type="checkbox"/>		
We Energies	<input checked="" type="checkbox"/>		
Midwest ISO, Inc.	<input checked="" type="checkbox"/>		
Salt River Project (Pfeister)	<input checked="" type="checkbox"/>		
Public Service Commission of SC	<input checked="" type="checkbox"/>		
Santee Cooper	<input checked="" type="checkbox"/>		
Entergy Services, Inc. (Generation & Mktg)	<input checked="" type="checkbox"/>		

4. The latest version of the Reliability Standards Development Procedure requires that each standard include “violation severity levels” rather than “levels of non-compliance’. Violation severity levels identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the “violation risk factor” appended to each requirement.) Note that these severity levels are ‘guidelines’ and variations from the above categories are acceptable. Do you agree with the violation severity levels for each of the proposed standards? If you disagree with any of the violation severity levels for the proposed standards, please identify the standard and requirement you feel has an incorrect violation severity level.

Summary Consideration: There was a typographical error in the violation severity levels that was identified by several commenters. This typographical error was corrected as follows:

2.2.2 Moderate: 85% < 12 month rolling average of the one-minute CPM ending in the last month measured ≤ ~~90~~ 95%

Question #4			
Commenter	Agree	Do not agree	Comment
Western Area Power Administration			See question 6.
Response: Please see the response to your comments on question 6.			
Independent Electricity System Operator			We agree with all the violation severity levels except BAL-007, Section 2.2.2: should the 90% be 95% (continuum from the threshold in 2.2.1)?
Response: This typographical error has been corrected as follows: 2.2.2 Moderate: 85% < 12 month rolling average of the one-minute CPM ending in the last month measured ≤ 95%			
Entergy Services, Inc. (Transmission Owners)		<input checked="" type="checkbox"/>	We suggest the Violation Severity Level for BAL-007-1 2.2 CPM be made internally consistent. The lower limit of the LOWER LEVEL is - less than 95 per cent. The upper limit of the MODERATE LEVEL is - less than 90 percent. It appears if CPM is greater than 90 percent but less than 95 percent there will be no violation of CPM. Is that correct?
Response: This typographical error has been corrected as follows: 2.2.2 Moderate: 85% < 12 month rolling average of the one-minute CPM ending in the last month measured ≤ 95%			
Hydro-Québec/TransÉnergie	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	BAL-007 has a gap between 90 and 95% between Lower and Moderate.

Consideration of Comments on 7th Draft of Balance Resources and Demand Standards

Question #4			
Commenter	Agree	Do not agree	Comment
<p>Response: This typographical error has been corrected as follows: 2.2.2 Moderate: 85% < 12 month rolling average of the one-minute CPM ending in the last month measured ≤ 95%</p>			
New York ISO NPCC CP9 Reliability Standards Working Group ISO New England		<input checked="" type="checkbox"/>	BAL-007 has a gap between 90 and 95% between Lower and Moderate.
<p>Response: This typographical error has been corrected as follows: 2.2.2 Moderate: 85% < 12 month rolling average of the one-minute CPM ending in the last month measured ≤ 95%</p>			
Santee Cooper		<input checked="" type="checkbox"/>	We agree with the Violation Severity Levels with the following exception: BAL-007-1 CPM Requirement. CPM in the range of 90-95% is not included in any of the violation severity levels. ("Lower" is listed as 95-100% while "Moderate" is listed as 85-90%.)
<p>Response: This typographical error has been corrected as follows: 2.2.2 Moderate: 85% < 12 month rolling average of the one-minute CPM ending in the last month measured ≤ 95%</p>			
Entergy Services, Inc. (Generation & Mktg)		<input checked="" type="checkbox"/>	<p>BAL-007 2.2 The CPM VSLs leave a gap between 90-95%. All performance below 100% should fall into one of the four categories.</p> <p>BAL-009 VSLs should be graduated such that the Severe is one where an entity takes no action to comply when directed; failure to immediately notify the RC of the inability to comply should fall into a Moderate or High Category.</p> <p>Bal-010 VSLs that are shown as High should be moved into Moderate, and those that are shown in Severe should be moved into High. Severe should be "not applicable."</p>
<p>Response: The typographical error in BAL-007 2.2 has been corrected as follows: 2.2.2 Moderate: 85% < 12 month rolling average of the one-minute CPM ending in the last month measured ≤ 95%</p> <p>Violation Severity Levels address how badly a requirement was violated. If an entity fails totally in meeting the requirement, then the severity level is 'HIGH'. Violation Severity Levels do not assess the reliability-related risk of the failure to comply – the reliability-related risk of failure to comply is addressed in the Violation Risk Factors assigned to each requirement.</p>			
Florida Reliability Coordinating Council		<input checked="" type="checkbox"/>	In general if these VSL are 'guidelines', as stated above, they should not be part of a NERC Reliability Standard.

Consideration of Comments on 7th Draft of Balance Resources and Demand Standards

Question #4			
Commenter	Agree	Do not agree	Comment
			<p>Although the violation severity levels (Lower, Moderate, High and Severe) are defined in the comment form provided and described as the basis for the DT's determinations, the levels are NOT defined in the current Reliability Standards Development Procedure. The term 'violation severity levels' is referenced generally in the Reliability Standards Development Procedure, version 6.0, adopted by NERC BOT, 11/1/2006 in the 'Compliance Elements of a Standard' section, as follows:</p> <p>(Violation Severity Levels) - 'Defines the degree to which compliance with a requirement was not achieved. The violation severity levels, are part of the standard and are balloted with the standard, and developed by the NERC compliance program in coordination with the standard drafting team.'</p> <p>Since the standards procedure does NOT include the definitions for Lower, Moderate, High and Severe, our main concern, again, is from a policy perspective. Although the definitions are included in the comment form, we feel this track will lead to confusion among stakeholders and regulators in this and other standard development activities. The process is requesting the industry to ballot and comment on a concept (Lower, Moderate, High and Severe) that is defined outside the reliability standards process and as such is subject to revisions and interpretations outside the process as well. This appears inappropriate and at the extreme will lead to inconsistent understanding, measurement and enforcement of compliance actions.</p> <p>The levels should be defined in the Reliability Standards Development Procedure prior to inclusion in balloting any standards.</p>
<p>Response: The intent in providing the same set of guidelines for distinguishing between various Violation Severity Levels was to bring consistency to the determination of appropriate Violation Severity Levels. These guidelines were reviewed and endorsed by both the Standards Committee and the Certification and Compliance Committee.</p>			
Detroit Edison		<input checked="" type="checkbox"/>	<p>Detroit Edison suggests the following change to BAL-010-1, section 2, Violation Severity levels. Suggest 2.3.1 be listed as moderate rather than High. The entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. The entity has the documented methodology but that methodology is non-compliant.</p>
<p>Response: Most commenters agreed with the proposed Violation Severity Levels and they were not changed.</p>			

Consideration of Comments on 7th Draft of Balance Resources and Demand Standards

Question #4			
Commenter	Agree	Do not agree	Comment
WECC Reliability Coordination Comments Work Group		<input checked="" type="checkbox"/>	BAL-008 R2 appears to be miswritten, and until that requirement is rescripted, the RCCWG disagrees with the Violation Security Levels that pertain to that requirement. As currently scripted, BAL-008 R2 requires the Reliability Coordinator to take actions previous to a Frequency Abnormal Limit Violation. However, the Interconnection frequency can fall below the Frequency Alarm Limits much quicker than a Reliability Coordinator could make notifications. There will be situations when the Reliability Coordinator has no opportunity to make notifications prior to the violation.
<p>Response: There is no FTL Violation until interconnection frequency has exceeded its FTL for 30 minutes. FAL Low is set roughly three contingencies away from FRL and frequency-related tripping – the Reliability Coordinator should notice a change in frequency with sufficient time to direct its BAs to take action before reaching FAL.</p>			
Energy Mark, Inc.		<input checked="" type="checkbox"/>	The violation security level for CPM is set at "lower". This is the primary measure of interconnection frequency control and it has been demonstrated mathematically that there is a very high assurance that violation of this criteria indicates inadequate contribution to maintaining appropriate interconnection balance. Failure to meet this requirement has a direct effect on interconnection reliability and the probability that the interconnection will experience a cascading failure. It is incomprehensible that the setting of Mitigation Time Horizon and Violation Severity Level for this measure puts it in the same category as the completion of paperwork for the BAAL measure. In fact, this measure shoulders more of the load of insuring interconnection balancing reliability than any of the other requirements in this posting yet, it has been given one of the lowest weightings with respect to its compliance value. Just because a measure takes a long time to complete does not mean that it is any less important.
<p>Response: The Violation Risk Factor for CPM was determined by the Violation Risk Factors SDT by collecting and averaging stakeholder ratings. The risk factor assigned to CPM in the second survey of Version Violation Risk Factors was LOWER.</p>			
We Energies		<input checked="" type="checkbox"/>	BAL-010-1 Violation Severity Level 2.4.2. R2 does not address an updated methodology and does not require submitting the methodology. If the intended statement was a severe violation for not submitting an updated bias to NERC by December 1, it should be high not severe.
<p>Response: BAL-010-1 Violation Severity Level 2.4.2 had a typographical error that was corrected – the word, 'methodology' should not have been included – this typographical error has been corrected and the word, 'methodology' was removed from Level 2.4.2.</p>			

Consideration of Comments on 7th Draft of Balance Resources and Demand Standards

Question #4			
Commenter	Agree	Do not agree	Comment
<p>Violation Severity Levels address how badly a requirement was violated. If an entity fails totally in meeting the requirement, then the severity level is 'HIGH'. Violation Severity Levels do not assess the reliability-related risk of the failure to comply – the reliability-related risk of failure to comply is addressed in the Violation Risk Factors assigned to each requirement.</p>			
MRO		<input checked="" type="checkbox"/>	<p>The MRO notes that for BAL-007, no Violation Severity Level assigned to CPM between 90% and 95% Is this intentional?</p> <p>In BAL-008, increasing severity levels are assessed for lateness of reporting. The MRO recommends that late reporting should always have a VSL of Lower. In BAL-010, requirements 2.4.1, 2.4.2, and 2.4.3 are documentation and reporting requirements, and, as such, should have a VSL of Lower. BAL-011 has no assigned VSL.</p>
<p>Response: This typographical error has been corrected as follows: 2.2.2 Moderate: 85% < 12 month rolling average of the one-minute CPM ending in the last month measured ≤ 95%</p> <p>Violation severity levels identify how badly an entity missed in complying with the associated requirement – violation severity levels are not used to assess the impact on reliability of failure to comply with a requirement.</p> <p>The omission of violation severity levels for BAL-011 was deliberate. The standard is not expected to be enforceable since NERC is not a user, operator or owner of the bulk electric system. BAL-011 was retained as a standard to give stakeholders a 'say' in the formulas used to calculate frequency limits.</p>			
Southern Company Transmission	<input checked="" type="checkbox"/>		Southern Company Transmission agrees with the violation severity levels shown for each of the proposed standards.
<p>Response: Thank you for your support – note that there was a typographical error in one of the violation severity levels (2.2.2) and this has been corrected.</p>			
Tennessee Valley Authority	<input checked="" type="checkbox"/>		
Northern Indiana Public Service	<input checked="" type="checkbox"/>		
ITC Transmission	<input checked="" type="checkbox"/>		
Constellation Energy Control and Dispatch	<input checked="" type="checkbox"/>		
FirstEnergy Corp.	<input checked="" type="checkbox"/>		
Consumers Energy	<input checked="" type="checkbox"/>		

Consideration of Comments on 7th Draft of Balance Resources and Demand Standards

Question #4			
Commenter	Agree	Do not agree	Comment
Company			
Midwest ISO, Inc.	<input checked="" type="checkbox"/>		
Kansas City Power & Light Company	<input checked="" type="checkbox"/>		
Salt River Project (Pfeister)	<input checked="" type="checkbox"/>		
Public Service Commission of SC	<input checked="" type="checkbox"/>		
Manitoba Hydro	<input checked="" type="checkbox"/>		

Consideration of Comments on 7th Draft of Balance Resources and Demand Standards

5. If you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement please identify the conflict here. Similarly, if you believe that any requirement in this set of standards has an unnecessary adverse impact on energy markets, please identify the requirement and its adverse impact here.

Summary Consideration: While several commenters indicated there may be a potential for increased parallel flows with additional use of TLRs, experience in the field test has not shown this to occur. No 'actual' conflicts were identified.

Question #5			
Commenter	No known conflicts	Known conflict	Comment
Progress Energy Carolinas		<input checked="" type="checkbox"/>	Making Bal-011 applicable to NERC is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and operators of the bulk power system. Further, in the NOPR on NERC standards, FERC declined to approve those standards that applied to the RROs, in part because the RROs are not owners, users or operators. NERC likewise is not an owner, user or operator and so standards cannot apply to NERC.
Response: In its January 18, 2007 order, FERC did recognize that NERC may be assigned responsibility for some requirements in some standards.			
ISO New England Hydro-Québec/TransÉnergie NPCC CP9 Reliability Standards Working Group		<input checked="" type="checkbox"/>	There is a potential for increased parallel flows possibly resulting in additional use of TLRs with consequential adverse impact on markets.
Response: These increased parallel flows may result in either an increased or a decreased use of TLRs. There is nothing in the existing BAL Version 0 standards that limits these parallel flows. Note that the field test which has been underway for well over a year did not include any instances where a Reliability Coordinator attributed an operating scenario such as you've described, to operation under the proposed standards. If such a condition does occur in real-time operations, there are other standards that require actions to remedy the situation.			
New York ISO		<input checked="" type="checkbox"/>	There is a potential for increased parallel flows due to unscheduled flows due to BA's not close to zero ACE, possibly resulting in additional use of TLRs with consequential adverse impact on markets.
Response: Note that the field test which has been underway for well over a year, did not include any instances where a Reliability Coordinator attributed an operating scenario such as you've described, to operation under the proposed standards.			
Energy Mark, Inc.		<input checked="" type="checkbox"/>	This question is included here for the first time, yet it is one of the most

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Question #5			
Commenter	No known conflicts	Known conflict	Comment
			<p>important questions that should be included with every comment form. Markets work best when they have the least interference from outside rules that can cause the modification of contracts for the delivery of the primary product, electric energy. The ERO and the industry should, therefore, ask with every reliability standard, 1) how effective is this standard, and 2) what are the side effects of implementing this standard. This is important in all decision making processes. These questions can be asked in another manner. 1) How good is this standard at indicating a reliability problem?; What is the probability that a reliability problem will occur without this standard indicating a violation? This effectiveness of a standard is indicated by what is call Type I Error. This kind of measurement is also observed when the FDA tests a drug to see if it is effective, or when one considers the legal system with respect to the probability of someone being prosecuted for breaking the law. It is also important for any standard to be judged by the converse of Type I Error, Type II Error. Type II Error is the probability that the standard will indicate that a reliability problem was present when, in fact, there was no reliability problem. These events are call false positives. In the legal system, they occur when an innocent party is convicted and punished for a crime. In FDA terms, they occure when a drug causes detrimental side-effects or even the death of the patient. Whenever standards such as these reliability standards are developed and implemented, there is a natural trade off that must be made between Type I Error and Type II Error. The quality of this trade-off can be significantly influenced by the quality of the individual standards implemented. Better standards will jointly minimize both Type I Error and Type II Error. In the legal system, we have chosen a balance that allows larger Type I Error, letting the guilty go free, while minimizing Type II Error, convicting the innocent. In our drug regulation we attempt to balance the risks versus the rewards, but tend to weight the minimization of Type II Error more and accept greater Type I Error.</p> <p>Unfortunately, there has been little or no discussion with respect to the quality of the standards that we are developing with respect to the Type I</p>

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Question #5			
Commenter	No known conflicts	Known conflict	Comment
			<p>Error and Type II Error associated with the implementation of these standards. Past industry practice has been to minimize Type I Error without consideration of Type II Error on the industry. This has been acceptable because the detrimental effects of Type II Error were incurred by the same Vertically Integrated Utility as the effects of Type I Error. In this new restructured world, the detrimental effects of Type I Error may be incurred by different participants than the detrimental effect of Type II Error. Therefore, any new standards should be evaluated with respect to both Type I Error and Type II Error that will be incurred when they are implemented.</p> <p>I believe that this lack of discussion about the quality of these standards has significantly influenced the acceptability of the new standards to the industry. When the existing standards are compared to the new standards, the existing standards are assumed to be responsible for maintaining good reliability on the interconnections simply because they are the rules we have followed in the past. We have chosen not to judge them with respect to their effectiveness.</p> <p>Unfortunately, there is little in the way of solid scientific evidence or study that is available to confirm this feeling of effectiveness. It could be much like the 19th century doctor that bled their patients to help them get better because it appeared to have worked in the past.</p> <ul style="list-style-type: none"> - We do have studies that indicate the CPS1 and CPS2 perform the same function, but CPS1 performs that function better. - We also have significant experience from the field test of BAAL that CPS2 does not prevent transmission limit violations. If this were the case, then we should have observed at least one instance in which the lack of CPS2 during the field test would have resulted in a transmission limit violation, yet this did not occur. This is important because it leads us back to the main point of the problem. CPS2 is more restrictive than BAAL with respect to ACE error that both helps and hurts frequency. - If CPS2 could be relaxed for approximately half of the Eastern

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Question #5			
Commenter	No known conflicts	Known conflicts	Comment
			<p>Interconnection for a period exceeding 18 months without a single instance of a reliability problem resulting from the relaxation of CPS2, then what is the Type II Error resulting from continued enforcement of CPS2? This should be one of the main considerations when we look at the modification of our reliability standards.</p> <p>Which standards are better from the view of both Type I Error and Type II Error when one considers that Type II Error is detrimental to efficient market operations.</p> <p>This is of even greater importance when one considers that much of the protection of the consumers of this industry has been assumed to be provided by the implementation of efficient markets.</p>
<p>Response: FERC has encouraged NERC to be more proactive in identifying standards that may have these conflicts and NERC staff has committed to including this question during the development of all its reliability standards. Thank you for your very thoughtful comments – your support during the development of this standard has been of great help to the drafting team.</p>			
Western Area Power Administration			See question 6.
<p>Response: See the response to question 6.</p>			
Tennessee Valley Authority		<input checked="" type="checkbox"/>	
WECC Reliability Coordination Comments Work Group		<input checked="" type="checkbox"/>	
Entergy Services, Inc. (Transmission Owners)		<input checked="" type="checkbox"/>	
Entergy Services, Inc. (Generation & Mktg)		<input checked="" type="checkbox"/>	
ITC Transmission		<input checked="" type="checkbox"/>	
Constellation Energy Control and Dispatch	<input checked="" type="checkbox"/>		Other than previously discussed conflict with the NERC DCS standard.

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Question #5			
Commenter	No known conflicts	Known conflict	Comment
<p>Response: The drafting team does not believe there is a conflict between the DCS standard and the proposed standards – under the field test, entities have been operating to both the DCS standard and the proposed standard for more than a year without any identified operating conflicts.</p>			
Northern Indiana Public Service	<input checked="" type="checkbox"/>		
Detroit Edison	<input checked="" type="checkbox"/>		
FirstEnergy Corp.	<input checked="" type="checkbox"/>		
Florida Reliability Coordinating Council	<input checked="" type="checkbox"/>		
Consumers Energy Company	<input checked="" type="checkbox"/>		
We Energies	<input checked="" type="checkbox"/>		
Southern Company Transmission	<input checked="" type="checkbox"/>		
Midwest ISO, Inc.	<input checked="" type="checkbox"/>		
American Transmission Co.	<input checked="" type="checkbox"/>		
Midwest ISO, Inc. (group)	<input checked="" type="checkbox"/>		
Kansas City Power & Light Company	<input checked="" type="checkbox"/>		
Salt River Project (Pfeister)	<input checked="" type="checkbox"/>		
Public Service Commission of SC	<input checked="" type="checkbox"/>		
Manitoba Hydro	<input checked="" type="checkbox"/>		
Independent Electricity System Operator	<input checked="" type="checkbox"/>		
Santee Cooper	<input checked="" type="checkbox"/>		

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

Question #6	
Commenter	Comment
Tennessee Valley Authority	<p>1. BAL-007-1, Requirement 1 states: "The BA shall balance its resources and demand on real time so that its ACE does not exceed its BA ACE Limit." As defined by BAL-007-1 Attachment #1.</p> <p>When referring to the ACE above, is that instantaneous ACE or is it the one minute average? if it is the one minute average - then perhaps the requirement should be changed for clarification.</p> <p>2. We fully support moving the standard(s) to ballot. The requirements of the BAL-007 standard place defined parameters around when the System Operator must take action to correct the Balancing Authority's impact on the Interconnection frequency - the real-time indication that generation control action is necessary is clearly understood. The Standard forces the right actions to happen when necessary if a Balancing Authority's ACE is beyond BAAL, but does not force unnecessary generation control action when the operation of the BA is supporting the Interconnection frequency. This standard also provides clear indication to the Reliability Coordinator of required actions when a BA is operating outside acceptable limits and Interconnection frequency is beyond the limits set for FTL.</p> <p>3. As there was no area to list the Regional Differences we would offer the following: The somewhat unique configuration of the MISO market over multiple Balancing Authorities should be considered in allowing certain BA functions associated with generation performance to be provided by the RTO and its market dispatch, with the RTO taking full responsibility for compliance to CPM and BAAL, while distributed functions such as tie-line monitoring and coordination remain at the local centers of the internal BAs retaining the associated compliance responsibility.</p>
<p>Response:</p> <p>1. This is clock-minute average of ACE – the standard was modified to include this clarification.</p> <p>2. Thank you for your support.</p> <p>3. If MISO wants a Regional Difference (now called a Regional Variance), MISO must follow the process in the Reliability Standards Development Procedure for obtaining that variance.</p>	
WECC Reliability Coordination Comments Work Group	<p>Please see the comments above in 4. BAL-008 R2 needs to be rewritten to identify the time frame inside of which a Reliability Coordinator must make notifications and directives to Balancing Authorities when there is a Frequency Abnormal Limit Violation. No previous notification can be made for sudden Frequency Abnormal Limit Violations.</p>

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Question #6	
Commenter	Comment
<p>Response: Most commenters supported this requirement as written.</p>	
Northern Indiana Public Service	NIPS is currently under the field trial. Trial is going very good and would like to see the standards adopted.
<p>Response: Thank you for your support of this new set of standards.</p>	
Entergy Services, Inc. (Transmission Owners)	<p>1. The industry has determined that NERC reliability standards need to be more definitive as to which entities the standards are Applicable. Therefore, Entergy strongly suggests that all Applicability assignments in ALL standards and requirements be changed to be very specific. Therefore, we suggest the Applicability of each standard be changed to - ALL REGISTERED xxx, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD, where xxx is the functional entity to whom the standard applies. Therefore, the Applicability of BAL-007-1 should not be Balancing Authoity but should be changed to - ALL REGISTERED BALANCING AUTHORITIES, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD; BAL-008-1 should be - ALL REGISTERED RELIABILITY COORDINATORS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD; BAL-009-1 should be - ALL REGISTERED BALANCING AUTHORITIES, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD; BAL-010-1 should be - ALL REGISTERED BALANCING AUTHORITIES, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD; BAL-011-1 should be - NERC, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD.</p> <p>2. BAL-008-1 R2 contains the statement that if there is a FTL Violation the RC shall PREVIOUSLY have taken We found the use of the term PREVIOUSLY in this context somewhat confusing and we suggest it be replaced with - BEFORE THE VIOLATION OCCURS.</p> <p>3. BAL-009-1 R1.1 has no VRF, MTH nor measure. We suggest adding to this Requirement a Violation Risk Factor of HIGH, Mitigation Time Horizon of REAL-TIME OPERATIONS, and the measure being lack of evidence for meeting R1.1.</p> <p>4. All of the Violation Risk Factors for all of the requirements of BAL-010-1 should be LOWER. The whole process including implementation of the Frequency Bias Setting will not cause cascading outages or uncontrolled separation of the Bulk Power System, even if that Setting is zero or non-existent.</p> <p>5. BAL-010-1 R2 contains a requirement that the new Frequency Bias Setting value be implemented on January 1 of the following year. Typically NERC has been requesting the data</p>

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Question #6	
Commenter	Comment
	<p>in mid-December, calculates L10 which is returned to the BAs by mid-January for February 1 implementation. Does NERC intend to change that practice to conform to the timing in this draft standard?</p> <p>6. Also, there is no measure for this requirement, BAL-010-1 R2. Should there be a measure?</p> <p>7. BAL-010-1 Compliance places the compliance monitoring responsibility on the RRO. Should that be the ERO?</p> <p>8. All the requirements in BAL-011-1 Frequency Limits have Mitigation Time Horizon values of OPERATIONS PLANNING. The frequency limits being developed and implemented in this standard will be used to control the real-time reliability of the Interconnection and could result in cascading outages or uncontrolled separation. Therefore, we strongly suggest the Mitigation Time Horizon for all these requirements be categorized as REAL-TIME OPERATIONS.</p>
<p>Response:</p> <p>1. Regarding Applicability- drafting teams were given the following guidance – if the standard will be applicable to all who register to perform a specific function, then there is no need to add more words to the applicability section – in other words, the ‘default’ is ‘all registered Balancing Authorities.’ The applicability section will only include additional clarification when the applicability is ‘other than all’.</p> <p>2. The drafting team used your suggestion and revised the sentence so that it is less awkward.</p> <p>3. The drafting team did not place a Violation Risk Factor and Mitigation Time Horizon on sub-bullets that had the same Violation Risk Factor and Mitigation Time Horizon as the main requirement.</p> <p>4. The Violation Risk Factors were developed by the Violation Risk Factors SDT with stakeholder input. The revised VRFs for BAL-010 are all LOWER.</p> <p>5. The standard will require a change to the current process – the standard requires reporting the frequency bias by December 1 – but this will not be for the purpose of calculating L10 as in the past.</p> <p>6. BAL-010-1 Requirement 2 is associated with Measure 2.</p> <p>7. The Compliance Monitor was changed to the Regional Entity.</p> <p>8. While the drafting team agrees that these requirements are very important, the requirements are not performed in real-time operations – and the drafting team agrees with most commenters that operations planning is the correct mitigation time horizon.</p>	
Constellation Energy Control and Dispatch	<p>(1) In BAL-007-1 Section 2.2 needs to be modified to include the 90%<12 month rolling average of the one-minute CPM ending in the last month measured < 95% range.</p> <p>(2) The standard was not field tested in the Eastern Interconnection by smaller Balancing Authorities (<100 MW) and the BAAL limits under the current calculation place these entities</p>

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Question #6	
Commenter	Comment
	at a higher probability of operating outside of BAAL limits. CECD would recommend the standard include a modification to BAAL limit calculations that include a minimum BAAL limit of 5-10 MW for frequency deviations of .03 Hz or less from scheduled frequency for entities with a Peak Load of < 300 MW.
<p>Response:</p> <ol style="list-style-type: none"> The typographical error in BAL-007-1 Section 2.2 has been corrected. The field test did include at least one smaller BA (approximately 2500 MW) and that BA did not demonstrate having a more difficult time complying with BAAL than larger BAs. Agree that the impact to a smaller BA is relatively larger than under L₁₀ as L₁₀ was designed to provide a disproportionate share of the benefits of interconnected operations to smaller BAs. <p>For example – compare a 1000 MW BA with a 10,000 MW BA. Under L₁₀, the smaller BA of 1000 MW had a band of + or -24 MW; the larger BA of 10,000 MW had a band of + or – 77 MW. The larger BA was ten times the size of the smaller BA, but had a band that was only three times as large as the band for the smaller BA.</p> <p>The technical justification for assignment of BAALs allocates the allowed frequency deviation in a linear manner, based on actual system data. The drafting team could not find any technical justification for the continuation of the use of L₁₀ allocation.</p>	

<p>FirstEnergy Corp.</p>	<p>1. The formulas for calculating BAAL (low) and BAAL (high) do not allow the BAAL limits to adjust for changes in scheduled frequency due to time error correction. This can result in Balancing Authority actions that are within the allowable BAAL limits but not conducive to correcting time error. We suggest that the 60Hz constant in these formulas be revised to a variable of scheduled frequency. This change effectively flattens the BAAL curves for fast time error corrections when scheduled frequency is at 59.98 to require tighter control over ACE during the condition where we are purposefully driving frequency low and the system vulnerability is increased. This change steepens the curve during slow time error corrections easing ACE control requirements during the condition where we are purposefully driving frequency at 60.02 and the system vulnerability is moderately affected.</p> <p>2. Recommend combining BAL-008-1 and BAL-009-1 into one standard titled Actions to return Frequency to within the Frequency Trigger Limit (FTL). Alternatively, recommend changing the title of BAL-008-1 to Reliability Coordinator Actions to return Frequency to within the Frequency Trigger Limit (FTL). Also recommend changing the title of BAL-009-1 to Balancing Authority Actions to return Frequency to within the Frequency Trigger Limit (FTL) as part of the alternative to combining BAL-008-1 and BAL-009-1. These recommended alternative title changes are proposed to better reflect the scope of each of these standards.</p> <p>3. In general, First Energy Corp. fully supports the BAAL Standards as a good method for bringing all of the generation resources available to bear on frequency deviations and disturbances rather than relying on one Balancing Authority that may already be struggling to recuperate to correct the frequency. We feel that the changes that we have recommended above will further strengthen the proposed standards.</p>
<p>Response:</p> <p>1. The BAAL should not change during a time error correction because BAAL is based on avoidance of tripping a frequency-based relay which does not change – this is a fixed value.</p> <p>2. Most stakeholders support the standards as posted.</p> <p>3. The drafting team appreciates your support but did not make the proposed changes.</p>	
<p>Florida Reliability Coordinating Council</p>	<p>We have a concern with providing the individual Interconnection frequency limits as a "supporting document" which is outside of the standards process. These are a critical element of a BAs calculations especially when demonstrating compliance to the standard. Because of the critical nature of the frequency limit numbers themselves, they should be part of the standard process and included within the body of a standard. This will ensure traceability of the numbers and provide clear direction and expectations to the industry. It will also ensure that any changes made to the limits are vetted within the formal process of the standards procedure and that changes in limits are communicated to the industry in an appropriate and</p>

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	<p>consistent manner.</p> <p>We recommend the limits be moved from the "supporting documents" and added as attachment #3 to BAL-007-1.</p> <p>We appreciate your consideration along with all the effort that has been put forth by the DT in developing these standards.</p>
<p>Response: If the drafting team includes the limits as part of the standard, then the standard will need to be revised when the limits are revised, and this isn't practical.</p>	
<p>New York ISO</p>	<ol style="list-style-type: none"> 1. The NYISO supports those positions presented by NPCC and ISO-NE. 2. The NYISO would also like the drafting team to consider the following concern associated with unscheduled flows due to BA's with large ACE values during periods when the system is at or close to 60 hz. As noted below there are no standards that restrict unscheduled flows except CPS. <p>The system is designed with as many knowns defined as possible and remove as many unknowns as possible. We do off line studies with most uncertainties resolved, identifying all variables such as ratings, in-service equipment and known transaction schedules.</p> <p>When we operate the system we hope to have the same certainties such that all flows on the system accounted for. We do accept some level of uncertainty between 10 of and 10 after the hour as schedules settle out. For the remainder of the hour, the system is expected to be at or close to steady state.</p> <p>When an area is off schedule, we introduce a level of uncertainty into that hour. Agreed at any given time the system could be secure, no overloads, even with the unscheduled flows. However, now that area could introduce flow changes to the system at anytime as they arbitrarily get back on schedule. This action could easily place facilities over limits and placing an unexpected burden on neighboring systems.</p> 3. Areas are expect to continually monitor system conditions and secure their individual system for overloads. Many areas would prefer to have all schedules identified, resolve internal overloads, and with some certainty expect the system to be in steady state for the remainder of the hour. <p>Currently there are no standards to address this issue. When IROL's are identified, only scheduled flows will be cut to reduce overloads and unscheduled flows due to areas with large ACE's are not impacted. The simple statement in the existing standard that asks RC's to coordinate with BA's to reduce large ACE's do not adequately address a true reliability issue. There is no accountability to reduce ACE values to zero, reducing the burden on other systems.</p>

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<p>Response:</p> <ol style="list-style-type: none"> 1. Please see the drafting team’s response to the comments submitted by NPCC and ISO-NE. 2. As you are aware, the industry did not support having this set of BAL standards address unscheduled (parallel) flows. Unscheduled flows (parallel) should be addressed with the development of the IROL standards. Note that the current CPS2 does not limit flows –it only restricts ACE 90% of the 10-minute periods each month. If you believe the IROL standards are insufficient to address these unscheduled flows – you can submit a SAR to develop additional requirements. The other standards are looking at unscheduled flows independent of ACE values. The impact of parallel flows on transmission facilities is the same whether they are scheduled or unscheduled. 	
<p>Midwest ISO, Inc.</p>	<p>We fully support moving the standard(s) to ballot. The requirements of the BAL-007 standard place defined parameters around when the System Operator must take action to correct the Balancing Authority's impact on the Interconnection frequency - the real-time indication that generation control action is necessary is clearly understood. The Standard forces the right actions to happen when necessary if a Balancing Authority's ACE is beyond BAAL, but does not force unnecessary generation control action when the operation of the BA is supporting the Interconnection frequency. This standard also provides clear indication to the Reliability Coordinator of required actions when a BA is operating outside acceptable limits and Interconnection frequency is beyond the limits set for FTL.</p> <p>As there was no area to list the Regional Differences we would offer the following: The somewhat unique confuration of the MISO market over multiple Balancing Authorities should be considered in allowing certain BA functions associated with generation performance to be provided by the RTO and its market dispatch, with the RTO taking full responsibility for compliance to CPM and BAAL, while distributed functions such as tie-line monitoring and coordination remain at the local centers of the internal BAs retaining the associated compliance responsibility.</p>
<p>Response: The drafting team appreciates your support in moving these standards to ballot. If MISO wants a regional difference, it must follow the process in the Reliability Standards Development Procedure to obtain that difference.</p>	
<p>American Transmission Co.</p>	<ol style="list-style-type: none"> 1. Standard BAL-009 Requirement 1 <p>ATC requests that language be added that states that the RC will order its BA to shed load if such action is appropriate. ATC is a stand alone transmission owner/operator and as such our system is exposed to violations (SOL/IROL) and/or damage do to a BA’s inability to maintaining its ACE requirements.</p> <p>Suggested Language for R1</p> <p>When Interconnection frequency exceeds the Frequency Trigger Limit (FTL) and the Reliability Coordinator directs the Balancing Authority to act, which may include load</p>

	<p>shedding, to adjust its Area Control Error (ACE), the Balancing Authority shall comply with the directive.</p> <p>This additional language highlights the importance of the option and reminds everyone of the possibility.</p> <p>2. Requirement 1.1</p> <p>ATC is concerned that this requirement grants the Balancing Authorities a greater ability to refuse a Reliability Coordinators directive during ACE event that could lead to instability, uncontrolled separation or Cascading outages that adversely impact the reliability of the Interconnection. This additional leeway for BA's to refuse an order will place a greater burden on the remaining entities to solve the BA's ACE event.</p> <p>IRO-001-1 Requirement 8</p> <p>Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such action would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.</p> <p>BAL-009-1 Requirement 1.1</p> <p>The Balancing Authority shall immediately inform its Reliability Coordinator if complying with the Reliability Coordinator's directive will endanger personnel; damage equipment; violate regulatory or statutory requirements; or if conditions are such that compliance with the directive is not physically possible.</p> <p>Concern:</p> <p>ATC is concerned with the phrase "or if conditions are such that compliance with the directive is not physically possible".</p> <p>By including the above phrase in the requirement the BA's have been set apart from all other entities that must follow an RC directive. In addition, since the measure does not require a BA to demonstrate their inability to physically perform the order they could refuse any order given by the RC without fear of having to demonstrate their physical inability.</p>
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	<p>Proposed Solution:</p> <p>ATC strongly request that the SDT remove the objectionable language from the standard. In addition we request that the qualifying language mirror that of IRO-001-1</p> <p>Suggested Language for BAL-009-1 R1.1</p> <p>The Balancing Authority shall immediately inform its Reliability Coordinator if complying with the Reliability Coordinator’s directive will violate safety, equipment, or regulatory or statutory requirements.</p> <p>3. Frequency Limits:</p> <p>FRLLOW 59.820 Hz</p> <p>Appears to be high for tripping of generation in the Eastern interconnection.</p> <p>This limit is going to cause some difficulty when coordinating with system restoration and under-frequency load shedding plans.</p> <p>4. FRLHIGH 60.18 Hz</p> <p>Appears to be to low for tripping of generation in the Eastern interconnection.</p> <p>Tf generators used these limits during the August 14th Blackout the area impacted would have been greater.</p> <p>In our footprint we observed frequency increase to 60.25 Hz.</p> <p>Looking on the web we found a frequency chart for the Knoxville, Tennessee area they recorded a frequency spike greater that 60.2 Hz.</p> <p>(http://www.enernex.com/special/blackout.htm) Pager “Preliminary Analysis of Measurement Data from New York Blackout of 2003” by Erich W. Gunther</p> <p>It was reported in the blackout report that parts of New York and Ontario experienced frequency deviations between 59.3 Hz – 63.0 Hz.</p> <p>“U.S.-Canada Power System Outage Task Force Cause of the August 14th Blackout” page 59.</p> <p>The narrowing of frequency limits is increasing the likely hood of future blackout events being larger in scope. Additionally this will increase the likelihood of generators going off-line during a frequency triggered event.</p> <p>5. BAL-007 and BAL-008</p>
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	<p>ATC recommends that the footnote for Violation Severity Levels in the Compliance section be removed. It does not add any value since "extenuating circumstances" is not defined in the standard. Rather the Santion Guidelines provides the latitude intended by the footnote.</p>
<p>Response:</p> <ol style="list-style-type: none"> 1. The Balancing Authority has many tools available to adjust ACE, and load shedding, although significant, is just one of them. The Reliability Coordinator can issue a wide array of directives to control limits – the Reliability Coordinator is required to correct IROLs by taking all necessary corrective actions, up to and including load shedding. 2. This language was supported by most commenters and provides clear direction and protection for both entities. 3. This was set at the highest value of load shedding on the Eastern Interconnection which is in FRCC and does not reflect the UFLS as established within each region. 4. During a prior comment period, stakeholders indicated support for symmetrically-based frequency limits. These limits are not intended to set new limits for tripping generation. 5. The footnote is identical to the footnotes used with the Coordinate Interchange standards and these were added to the standards at the request of stakeholders. 	
<p>Midwest ISO, Inc. (group)</p>	<ol style="list-style-type: none"> 1. BAL-008-1 R1.2 should only apply to those BAs violating BAAL standards in the same direction as frequency. The way it reads now would imply the RC should contact even those BAs not violating the BAAL. 2. For BAL-010-1, R1.2.2, should the Frequency Bias setting be equal to or greater than 1% of the estimated monthly peak Load and/or generation? 3. For BAL-011-1 Applicability 4.1, should ERO be inserted here rather than NERC to make it consistent with the other three standards?
<p>Response:</p> <ol style="list-style-type: none"> 1. The requirement as written, matches your suggestion. 2. The correction was adopted and is reflected in the revised standard. 3. This is NERC acting as a technical organization. 	
<p>ISO New England</p>	<p>Please see attached for a detailed discussion of ISO New England's additional comments.</p>
<p>Response: Please see the response to the comments.</p>	
<p>Kansas City Power & Light Company</p>	<p>I have the following additional comments:</p> <ol style="list-style-type: none"> 1. BAL-007-1: <ol style="list-style-type: none"> 1. Compliance 1.1: This should remain with the RRO since this applies to Balancing Authorities and Balancing Authorities are under RRO's. 2. BAL-008-1: <ol style="list-style-type: none"> R1: The Violation Risk Factor should be HIGH not MEDIUM. Frequency is an

	<p>interconnection problem and can have a high impact to reliability if allowed to persist in abnormally high or low state. This is no different than the HIGH designation offered for R2 in this same standard.</p> <p>3. BAL-009-1: Compliance 1.1: This should remain with the RRO since this applies to Balancing Authorities and Balancing Authorities are under RRO's.</p> <p>4. BAL-010-1: R3: The Violation Risk Factor should be LOW not MEDIUM. Changing the methodology for Frequency Bias calculation and implementing that calculation is no different reporting the Frequency Bias setting in Requirement R2 above it.</p> <p>5. BAL-011-1: R8: The annual review by NERC of the Frequency Trigger Limits, the Frequency Abnormal Limits and the Frequency Relay Limits is very important to the reliability of the interconnected system operation. This violation risk factor should at least be a MEDIUM from the LOW as it is proposed in the standard now. This would better support the violation risk factors of HIGH for the initial development and implementation of these limits in R1 through R7.</p> <p>6. It seems somewhat unusual for NERC to be responsible to develop the frequency limits in this standard obligating itself to fulfill reliability standard requirements. My mental picture of the structure under which the development of standards, the monitoring of standard adherence, and the enforcement of standards is founded on the notion that NERC is an independent organization overseeing standards development for the industry and the compliance monitor and enforcer of the reliability standards for industry entities. It seems inappropriate for NERC to be the monitor and enforcer of standards and at the same time an entity responsible to fulfill reliability standard requirements. What drew my attention to this concept is there is no accountability in the violation severity levels in BAL-011 if NERC fails to perform in meeting their obligation to adhere to requirements that have a HIGH reliability impact. Does that seem right? Perhaps this standard should be modified to elect or assign a Regional Reliability Organization in each of the interconnections (Eastern, ERCOT, WECC and Hydro-Quebec) to be responsible to perform this function? This would be similar in concept to what is done now in the administration for the correction of time error.</p> <p>7. In case the statements made in question 2 are not appropriate for that question, I have repeated them here:</p> <p style="padding-left: 40px;">Do not agree with replacing BAL-003 with BAL-010 for the following reasons:</p> <p style="padding-left: 80px;">A. Does not include the treatment of Joint Owned Units in the calculation of Frequency Bias currently in BAL-003, R4.</p> <p style="padding-left: 80px;">B. Does not include the treatment of Overlap Regulation Service and</p>
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	<p>Supplemental Regulation Service in the calculation of Frequency Bias currently in BAL-003, R6.</p> <p>C. Does not require the use of Tie-Line Bias in Automatic Generation Control unless the use of TLB is adverse to reliability or the interconnection in currently in BAL-003, R3.</p> <p>Do not agree with retiring EOP-002-2, R5 with the implementation of the proposed standards as there is nothing in the proposed standards to prevent a Balancing Authority from overcorrecting when frequency is high or low in complying to operate within the proposed BAAL limits or Frequency limits.</p>
<p>Response:</p>	<p>1, 3. Compliance will be assessed by a Regional Entity working for the ERO. The standard was modified to show that the Compliance Monitor will be the Regional Entity.</p> <p>2, 4, 5. The Violation Risk Factors were determined by stakeholders working with the Violation Risk Factors drafting team. Most stakeholders indicated that BAL-008-1 R1 should have a MEDIUM risk factor and this was not changed. For BAL-010-1: R3 most stakeholders indicated this should be LOWER and this is the rating that will be posted with the pre-ballot review version of this standard. For BAL-011, almost all of the violation risk factors for the requirements were revised (based on the results of the 2nd Violation Risk Factor Survey for V1 Violation Risk Factors) and only R1 is rated, 'MEDIUM' – all other requirements in BAL-011 are rated, 'LOWER'.</p> <p>6. FERC has recognized that there may be some requirements in some standards that are assigned to NERC. This may change in the future. NERC has technical committees that perform studies, conduct analyses, and perform other tasks critical to reliability. As envisioned, NERC would assign the task of developing limits to one of these technical committees. The limits would not be developed under the</p> <p>7. Please see the drafting team's response to these comments under question 2.</p>
<p>Western Area Power Administration</p>	<p>I applaud the drafting team efforts by keeping DCS in the proposed standards, but I reject the idea that a new SAR can be submitted to eliminate DCS after approval of this standard.</p> <p>As I had previously commented, I believe elimination of CPS2 will open the possibility of creating large inadvertent by some balancing authorities who will try to capitalize on having the flexibility of running huge inadvertent rather than meeting their load by relying on the Interconnection to fulfill their obligations. Elimination of CPS2 and L sub 10 bandwidth, removes the limits as how much a balancing authority's ACE can deviate from zero, thus, keeping the door open for some balancing authorities to create substantial amount of inadvertent flow, thus causing transmission over load on other parts of the Interconnection. The premises that if the frequency is at or around 60 HZ a BA with Bias of 100 MW can lean on the Interconnection in tune of thousands of MW, is going to take away the personal responsibility from each BA and shift that burden to other BAs. Elimination of CPS2 and personal responsibility for BAs to meet their load is analogous to having a bank which allows</p>

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	<p>certain group of its customers (BAs) to borrow large sums of money without considering the consequences and wellbeing of the bank and other customers. Believe me if any bank adopt this kind of policy they will eventually go bankrupt. Elimination of CPS2 criteria is removal of the limits which will eventually degrade the Interconnection's frequency to point of collapse, just like the bank in my analogy.</p> <p>Please note FERC's concern about balancing authorities' use of inadvertent compared to load serving entities that are held responsible to meet their load via energy imbalance charges and penalties. If the balancing authorities do not have to be responsible and are not hold accountable to meet their load, why should load serving entities inside the balancing authority be held to a higher standard? If this is not a discriminatory practice what is it?</p> <p>Removal of CPS2 criteria and subsequent L sub 10 limit, no matter how unscientifically it has been derived (based on the your response to my comment for the previous version of this standard), is just like removing all stop signs at the intersections and the consequence is chaos. In my opinion, CPS1 standard which is claimed to be science based plays no impact to the reliability of the interconnection because it is too loose. I have yet seen any entity failing CPS1 criteria no matter how poor their performance has been.</p> <p>Getting rid of CPS2 is elimination of responsibility and accountability and that is the last thing is needed for operating a reliable electric power system.</p> <p>Thanks for the opportunity to comment.</p>
<p>Response: Reliability standards don't address equity issues associated with inadvertent interchange. The subject of inadvertent is addressed by NAESB Business Practices.</p>	
<p>Manitoba Hydro</p>	<p>1)Manitoba Hydro was part of the field test and and is comfortable operating to BAI 007. Manitoba Hydro contributed to frequency regulation, minimized CPM2 violations and our inadvertant account has not been negatively impacted.</p> <p>(2)Where there are references to data retention periods (BAL-007-1 Compliance 1.3, BAL-008-1 Compliance 1.3,BAL-009-1 Compliance 1.3, BAL-010-1 Compliance 1.3), the period should be phased in with the effective date of each standard. In this way a standard requiring three years of data retention would not be fully enforced until three years after the effective date.</p> <p>(3)It is not clear from the current wording as to what impact data retention has on violation of the standard since it is not included in any of the severity levels.</p> <p>(4)In regards to BAL-010-1, Compliance section 1.3, last paragraph ... "NERC shall keep the latest version of the Frequency Bias Setting submitted by each Balancing Authority." NERC</p>

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	<p>should also post, as a reference document to this standard, the current and past years frequency bias values for each BA and totaled by region and interconnection. Any mid year updates to this document should be posted as a revision, and communicated to the Balancing Authorities.</p>
<p>Response:</p> <ol style="list-style-type: none"> 1. The drafting team appreciates your support of these proposed standards. 2. Data retention is used to support compliance and starts when the standard becomes effective. Entities are not required to keep data before the standard becomes effective. 3. The intent in keeping data is to ensure that there is sufficient evidence (as outlined in the measures) to demonstrate compliance. Keeping data is not the same as a 'performance' requirement and data retention requirements do not have any associated violation severity levels. However, if an entity hasn't kept data to demonstrate compliance, then that entity is assumed to be non-compliant with the associated requirement. 4. The language you've proposed would be an additional requirement assigned to NERC. It isn't clear how this new requirement would improve reliability. 	
<p>Hydro-Québec/TransÉnergie</p>	<p>Please see the attached file for HQTE's additional comments in relation to a single Balancing Authority Interconnection.</p>
<p>Response: Please see the responses to your comments.</p>	
<p>Independent Electricity System Operator</p>	<p>(1) The SDT in its response to comments indicate that [...the drafting team converted BAL-011 back into a reference document. The drafting team will ask the Standards Committee for approval to post this reference with the proposed standards so that it will be accessible to all stakeholders.]</p> <p>The posted set includes Standard BAL-011, which is assigned the violation risk factors and the mitigation time horizons but not the violation severity levels. Is BAL-011 meant to remain as a standard or to be converted as a guide (which should not include any requirements and VRFs)?</p> <p>If BAL-011 should remain as a standards, then we feel the VRFs of HIGH for R1 to R7 should be changed to MEDIUM as the V1 VRF survey so indicates, and the violation severity levels should be developed.</p> <p>If this is meant to be a guide only, then it should not be posted in the same set along with BAL-007 to BAL-010, or be clearly indicated as a guide along the lines as the guide established for relay settings (Relay Loadability Standard - PRC-023) as the BAL-011 document is purely a formulation document intended to provide guidelines for establishing critical frequency (High and Low) settings.</p> <p>(2) Violation Severity Levels for BAL-007 - Point 2.2.4 - "...12 month rolling average of the CPM ending in..." could be written as "...12 month rolling average of the one-minute CPM</p>

	<p>ending in..." for consistency with the other points in this section.</p> <p>(3) VRF for requirements seem to be inconsistent - R2.3 in BAL-008 has been rated "MEDIUM" by both the Drafting Team and Stakeholders, but is indicated as "LOWER" in the document.</p> <p>(4) The Standards document appears to be cluttered with the indication of Violation Risk Factors and Mitigation Time Horizon, especially in cases where the main requirements and sub-requirements differ in their ratings and applicability - is there a better way to indicate these?</p> <p>(5) In BAL-008, Violation severity levels indicate "late" submission in days - are these "calendar" days or "business" days - shouldn't it be the latter?</p> <p>(6) We find R2 of BAL-008 a bit confusing and does not stack up well with R1. We suggest a minor change to the sentence such that it reads: "If there is an FTL Violation or an FAL Violation, each Reliability Coordinator within the affected Interconnection shall take the following actions to try to return frequency to within the Frequency Trigger Limits." for clarity.</p> <p>(7) In BAL-010, the Compliance Monitoring Authority is the "Regional Reliability Organization" - shouldn't this be the "Electric Reliability Organization" as with all the previous BAL standards?</p> <p>(8) Under Section D of BAL-010, Items 2.4.2 and 2.4.3 read almost the same except for the different requirements (R2 and R3). we believe 2.4.2 is incorrect. It should read: "The updated Frequency Bias Setting was not submitted to NERC, and implemented in accordance with R2." since R2 requires the submission of Frequency Bias setting, not the methodology which is required by R3.</p> <p>(9) There has been discussion in the industry on the potential increase in parallel flows following implementation of these BAL standards. We urge NERC to put in a place holder, the development plan for a standard that aims at controlling, minimizing and countering the increase in parallel flows if operating experience shows a linkage between the increase in parallel flows and the use of BAAL that replaces the CPS measures.</p> <p>(10) An editorial correction - In the BAL-008 document, under Purpose, it currently reads as: "To maintain Interconnection frequency within a predefined frequency limits under all conditions..." - This should read as: "To maintain Interconnection frequency within predefined frequency limits under all conditions..."</p>
<p>Response: 1. When the drafting team responded to the comments on the initial ballot of the proposed standards, the drafting team had intended to remove BAL-011 from the set of proposed standards and convert BAL-011 to a reference. Subsequent to the posting of its response to comments, the drafting team was advised that FERC may accept some standards with requirements assigned to NERC. Since most stakeholders seemed to support keeping BAL-011 as a</p>	

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<p>standard, the drafting team did change its mind and did not convert BAL-011 to a reference document.</p> <p>2. The drafting team adopted your suggestion and modified the violation severity level language so it more closely matches the language in the associated requirement.</p> <p>3. This was a transposition error and has been corrected to 'LOWER'.</p> <p>4. The drafting team is following the format it was provided. We hoped that putting the risk factors and mitigation time horizons in parentheses and in an italic font would help separate the compliance elements from the requirement. At this point, we don't have a better format to use.</p> <p>5. The standard was modified to clarify that these are 'business' days – this supports your suggestion.</p> <p>6. The standard was changed based on other comments to clarify that these actions need to take place, 'Prior to' the violation.</p> <p>7. Following the posting of this set of standards, the drafting teams were advised to begin using, 'Regional Entity' rather than "ERO' and the SDT made that change to this set of standards.</p> <p>8. The drafting team corrected this typographical error.</p> <p>9. Anyone can submit a SAR to address the development of a new standard – at this point, this drafting team is not planning to submit a SAR to address parallel flows. If experience with the standard shows an increase in parallel flows, we would expect the Operating Reliability Subcommittee or the Resources Subcommittee to submit a SAR for a new standard.</p> <p>10. The drafting team corrected this typographical error.</p>	
Santee Cooper	<p>Comment 1: Consideration should be given to identifying a process associated with BAL-011-1 whereby industry input is sought prior to issuing frequency limit changes.</p> <p>Comment 2: We were not asked if we agreed with Violation Risk Factors assigned to the requirements. (We do agree with the factors assigned)</p>
<p>Response:</p> <p>1. If NERC wants to modify the formulas used to calculate these limits, NERC would need to submit a SAR to change the formula, and would need to seek stakeholder support for the change.</p> <p>2. The violation risk factors for this set of standards were developed, with stakeholder input, by the Violation Risk Factors drafting team.</p>	
Entergy Services, Inc. (Generation & Mktg)	<p>1. The "Purpose" section of BAL-007 through BAL-009 uses semi-colons to separate the descriptions of undesired events. This is confusing and the use of commas would be appropriate.</p> <p>2. BAL-007 R1 has no associated measure. An appropriate measure would be "The Balancing Authority shall have evidence that its clock-minute ACE did not exceed the clock-minute BAAL for more than 30 consecutive clock-minutes."</p> <p>3. BAL-007 Attachment 1 contains definintions of the terms used in the equation. The BAAL low & high terms and the Bi have an "i" prior to the parameter unit of measure. There is no explanation as to what this "i" means and it appears to be unecessary. Also, no where does</p>

	<p>it say that this calculation is a clock-minute average - this needs to be very clear.</p> <ol style="list-style-type: none"> 4. BAL-008 R2 is confusing and redundant. Recommend deleting R2 totally and modifying R1 to state "If the duration of a Frequency Event exceeds five consecutive clock-minutes or if an FAL is exceeded..." 5. BAL-009 why is this a separate standard from BAL-008 which also contains actions required to return within FTL? Other than than the applicable entities these standards address the same thing. 6. BAL-010 R2 contains vebiage regarding implemenation that duplicates R4. Recommend deleting "shall implement its new Frequency Bias setting on January 1 of the following year." R4 already requires that the BA use the latest approved settings. This will also allow flexibiity for allowing NERC to issue the settings after January 1st (as they seem to do now). The standard should also state where the approved settings can be found (if not included as an attachment). 7. BAL-011 lists NERC as the applicable entity with an unnamed "third party" as the compliance monitor. This third party should be established and identified. Who is responsible for ensuring the third party performs a complaince check, and how often will they do it? 8. BAL-011 R9 states that 30 days notice will be provided before implementing new FTLs, FALs, FRLs. The standard need to contain language that allows a shorter implementation time for grid reliability. 9. Where will the Frequency Limits for BAL -007-011 reside? Can they be an attachment in BAL-011? These limits need a home. At minimum, BAL-011 should state where to find the limits. 10. We support moving the standards to ballot with the minor changes suggested above.
<p>Response:</p> <ol style="list-style-type: none"> 1. When a series of phrases is in a sentence, it is acceptable to separate the phrases by semicolons. 2. M1 measures R1. If the BA does exceed BAAL for more than 30 consecutive clock-minutes, there is a BAAL violation and an associated report of the violation. Collecting data to show that you were compliant with R1 all the time could be overwhelming – so the measure only looks at the evidence when there is non-compliance. During the refinement of this set of standards, stakeholders indicated they did not want to be forced into burdensome data collection and retention just to show compliance with the requirements. 3. 'i' stands for a particular Balancing Authority and this is defined in the legend for the formula which states: B_i is 	

Frequency Bias for Balancing Authority, i (MW/0.1 Hz)

4. R1 and R2 are looking for different performances –
 - R1 requires the RC to act whenever Interconnection frequency falls below FTL_{Low} or exceeds FTL_{High} for five consecutive clock-minutes. The RC's directives require BAs that are hurting frequency to return ACE to within BAALs
 - The RC's directives in R2 require BAs that are hurting frequency to return ACE to zero.Note that several commenters indicated that R2 was confusing as originally written, and the drafting team revised R2 so that it now begins with the phrase, 'Prior to an FTL Violation or an FAL Violation. . . '
5. When originally drafted, this set of standards was a single standard. The drafting team was directed to subdivide the large standard into several smaller standards. The team agrees that the two standards could easily be merged into a single standard – however there is nothing wrong with leaving these as two separate standards.
6. The intent of these requirements was to provide hard and fast dates by which the BAs have to have their information to NERC and by which NERC has to turn around the information for implementation by the BAs. The current practice is somewhat loose with numbers dribbling in throughout January and implementation, nominally on February 1, often delayed as new numbers come in. The proposed standards provide clear dates and, for administrative reasons, start on January 1 of each year. Since R4 was intended to cover BAs that, due to various circumstances need to change their Frequency Bias during the year, this is not redundant with R2.
7. As envisioned, the third party monitor is an auditor without vested interest in the outcome for NERC, appointed to monitor NERC's compliance with the standard. The drafting team does not have any control over 'who' or 'what organization' might be appointed to perform this task.
8. The 30 days gives entities time to update their tools to reflect the new limits.
9. The Standards Committee has agreed that 'references' (and the limits are considered a 'reference') associated with standards should be posted on the 'Approved Standards' web page with a link to the associated reference.
10. The drafting team appreciates your support.

Supplementary Comments from ISO-NE

Mike Potishnak
October 4, 2006
Revised January 19, 2006

Introduction

On behalf of ISO New England and in conjunction with the efforts of the NPCC (CO-1) Control Performance Working Group, the author has been tracking the development of the Balance Resource And Demand Standard from the standard authorization phase, through its theoretical development and comment phase, and through the field trial. After careful review of the proposed Balancing Standard and its implementation plan, ISO New England will be voting against the proposed standard and its implementation plan.

Prior documents have extensive technical detail to support this position. This document will summarize the unresolved concerns with the standard and its implementation plan in the next section. The final section describes possible alternatives that could be taken to change ISO New England's position to be supportive.

Two noteworthy improvements have been made to the Balancing Standard since its initial rejection by the industry. The DCS, and its requirement to carry sufficient contingency reserve to cover the First Contingency Loss, will now be retained. Also, the inappropriate penalties assigned to Reliability Coordinators for some frequency limit violations have been replaced with a more reasonable approach. These necessary changes, however, are not sufficient to remedy other substantial deficiencies that were noted previously, and the highlights of those deficiencies remain in the text to follow.

Problems With The Balancing Standard And Its Proposed Implementation

1. Lack Of Coordination With Other Standards

When a Balancing Area experiences a significant change in the balancing of its load and generation, both the system frequency and its power interchange with its adjacent Balancing Areas are affected. However, this standard, by design is only concerned with frequency. While other standards address transmission issues to some extent, none of them call for a limit on ACE similar to CPS 2, nor do they specifically call for action to adjust an energy imbalance causing transmission problems in other Balancing Areas. NPCC studies using the Balancing Standard demonstrated that significant unscheduled net flows into or out of the Balancing Area will pass under the radar screen of the BAAL limits. A significant energy mismatch in a Balancing Area that causes undesirable net tie line flows that aggravate transmission constraints in other Balancing Areas will go unchecked by the BAAL limits when the frequency is at typical values. When the root cause of a transmission problem external to the Balancing Area is caused by its energy mismatch, the BAAL limits may be very wide and provide the operator with erroneous feedback that their energy balancing function is "OK". Also, operators of affected external Balancing Areas may be unaware that another Balancing Area's energy mismatch is causing

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overloads, and may cut schedules under its control which are not the root cause of the problem to try to eliminate the overload, and the problem may still persist.

While the current plan is to retain the DCS, given that most Balancing Areas use the 80% of First Contingency Loss threshold, it will not apply for lesser resource contingencies, nor will it apply for mismatches that arise without the occurrence of a contingency. In summary, the implementation plan does not adequately protect against unscheduled net flows due to energy mismatches in Balancing Areas.

Even if the text of transmission related standards would specifically call for a Balancing Area to adjust its ACE when it causes transmission problems outside its Balancing Area, the permissiveness of the BAAL limits could result in more frequent IROL/ SOL violations, possibly or greater magnitudes and durations than experienced historically, effectively compromising reliability.

The fledgling Frequency Response Standard (FRS) needs to interact smoothly with the Balancing Standard in areas such as determining how much response will be provided in a timely manner when contingencies occur. Yet this standard is lagging well behind the Balancing Standard in its delivery to the industry, and important parameters have yet to be determined. (Some relevant technical detail is provided in the section addressing the methodology.)

Response: If ISO-NE has been tracking this standard, then ISO-NE must be aware that stakeholders do not support addressing transmission flows with this set of BAL standards. We've encouraged ISO-NE to develop and submit a SAR that will address your concerns.

It is unfortunate that ISO-NE has rejected the drafting team's repeated invitations to participate in the field test.

The field test of these new standards has been underway for more than a year and so far the operational problems you've described have not occurred. Note that CPS2 is only in effect for 90% of the 10-minute periods per month – so the scenarios you've described can occur undetected, under CPS2.

There is no Frequency Response Standard – just a SAR and so far that SAR is limited to collecting data needed to model each interconnection's frequency response.

2. Concerns With The Methodology For Developing BAAL Limits And Durations For Which Their Violation Is Permissible

In reviewing the BAAL methodology, comments offered over time by others (e.g., Jaleeli, Illian, and Blohm), and the Drafting Team's replies to NPCC and other comments, there are several methodological concerns that are unresolved and may affect reliability. They are listed briefly below.

- 2.1 The method for determining the frequency abnormal low limit and frequency trigger limit uses a once in ten year criterion for placing them above the low frequency relay setting. This is an intermediate variable, and an estimate of what the actual expected failure rate would be for realistic operating scenarios has not been provided to the industry. The method should allow for that ultimate quantified target of reliability to be

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known and reviewed, and the method should allow for an entity such as the NERC Operating Committee to review and adjust the target, and subsequent limits over time.

Response: Most stakeholders supported the once in ten year approach. The FAL establishes this limit with the FTL providing a single contingency above the maximum acceptable risk as defined by the FAL. Several presentations have been given to the NERC Operating Committee and these presentations were very well received.

2.2 The method only addresses independent generation losses in the development of BAAL limits. Experience has shown that extreme weather events that happen far more frequently than once in ten years can be a significant source of dependency. Also, Jaleeli notes that most frequency events are the result of coincidental generation control practices that are not the result of a large contingency, which substantially challenges the validity of the assumption of independent generation losses as the basis for BAAL limit development. Resultant limits are very sensitive to the assumption of independence, and this issue has not been addressed satisfactorily. The ability of BAAL limits to deliver the intended level of reliability is challenged by this shortcoming.

Response: The drafting team makes the assumption that the most severe single contingency identified by each Balancing Authority is independent as required by other NERC standards. This contingency should be the same contingency used in other operating and planning criteria.

2.3 The method basically uses the average value of an interconnection's primary frequency response (load response, inertial effects, and generator governor response but not AGC response) in determining frequency limits above the low frequency relay limit. However, this response often does not appear until 10 seconds has elapsed. However, point "C", which is a post-contingency valley frequency, occurs 3 to 6 seconds after the contingency. Also, under-frequency relays operate in less than 1 second. It is not known what fraction of the primary response will be available in a timely manner. This would introduce a bias of setting frequency limits to be too low for the targeted level of reliability, and jeopardize reliable operations. Also relevant but of lesser importance is that the frequency response of an Interconnection is known to have a statistical distribution of values. Use of the average value may also jeopardize reliability during periods when a lesser value applies. The ability of BAAL limits to deliver the intended level of reliability is seriously challenged by this shortcoming.

Response: The phenomena described is more in the purview of the proposed Frequency Response Standard than that of the BRD standards. The "once in ten years" FAL with a single contingency above it would appear to provide sufficient margin above the under frequency relays to prevent this phenomena from occurring.

2.4 The 30 minute period for compliance with BAAL limits was chosen to be consistent with other standards and is not based on a specific calculation of risk. The ability of BAAL limits to deliver the intended level of reliability is challenged by this shortcoming.

Response: The initial methodology proposed by the SDT was to use the 50% probability of the next generation contingency as T_v . This turned out to be much greater than 30 minutes. In addition, it was shown that the time based risk of violating FTL was directly

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proportional to the rate of frequency change and not a fixed value. The SDT decided that a variable time limit would not be acceptable and presented the 30 minute T_v to the industry in the first draft of the standards. The question was asked of industry if they preferred a variable T_v or a fixed T_v and the reply was overwhelmingly for a fixed value.

- 2.5 Jaleeli notes that BAAL limits are based on the deviation of frequency from 60 Hz, as opposed to the deviation of frequency from the low frequency relay limit, which is to be avoided. The resultant BAAL limits from the two methods are different. The Drafting Team has not provided an explanation for the difference nor the overall impact on reliability (e.g., are the resultant limits more or less conservative) in their reply to this author's inquiry during the comment phase on this topic, making it difficult to evaluate the reliability impact of this choice.

Response:

Mr. Jaleeli is correct in that the BAAL limits are derived from a deviation from 60 Hz. This deviation, however, is calculated such that if all Balancing Authorities within the interconnection are operating exactly at their BAAL limit the Interconnection frequency will be exactly at its Frequency Trigger Limit (FTL). The FTL is set one contingency away from the maximum acceptable interconnection frequency risk, the once in ten Years Frequency Abnormal Limit (FAL), and thus links BAAL limits directly back to Interconnection risk.

- 2.6 The reliance on CPS 1, with its yearly view and its absence of time of day monitoring, is insufficient to assure adequate control performance without CPS 2.

Response: The field test of these new standards has been underway for more than a year and so far there have not been any operational problems attributed to the field test. Note that CPS2 is only in effect for 90% of the 10-minute periods per month so it doesn't provide control under all scenarios. Stakeholders overwhelmingly supported the retirement and replacement of CPS2.

- 2.7 The application of BAAL limits to single Balancing Area Interconnections has been called into question by HydroQuebec and the NPCC, and a more flexible and reliable alternative has been provided to the Drafting Team. The imposition of BAAL limits as formulated by a design for multi-area Interconnections is inappropriate. (One minute sampling, three tiers of frequency limits, and a thirty minute tolerance to BAAL limit violations might not be the most reliable approach, and the reporting required to support this standard, that does not fit well, could be burdensome, nonproductive, and not address the true reliability needs.)

Response: ERCOT has been participating in the field test as a single BA interconnection without problems attributed to the proposed standards. Because ERCOT is also an asynchronous interconnection, its CPM1 and BAAL measure boil down to a measure of Interconnection frequency deviation – ERCOT's net interchange deviation from schedule is effectively 0 at all times.

ERCOT has a waiver from CPS2 and had indicated problems with DCS. Until ERCOT clamped down on schedule errors, almost all of its major frequency deviations had no unit trip associated with them, so they completely escaped DCS measurement. ERCOT has indicated that it does not anticipate requesting an interconnection-wide regional difference from compliance with this set of standards.

It is unfortunate that HQ elected to refrain from voluntary participation in the field test. One of the purposes of the field test was to test the impacts of operating under the proposed standards under very controlled conditions – when the reliability coordinators had the option of curtailing the field test at any time there was a concern that operating under the proposed measures was having an adverse impact on reliability. Note that during the field test, no reliability coordinator – including ERCOT’s reliability coordinator - curtailed the field test for any reason.

In addition, the reporting requirements have not proved burdensome.

3. Reliability Coordinator Issues

There is a concern for the additional workload imposed on Reliability Coordinators to primarily allow Balancing Areas to relax their control.

Response: Reliability Coordinators participating in the field test have not indicated that compliance with the proposed standards results in additional workload – on the contrary, the participating Reliability Coordinators have expressed gratitude for the specificity of the new limits that provide explicit actions to preserve interconnection reliability.

Changes That May Gain ISO New England’s Support

Progress would need to be made in each of the following areas.

1. As part of the standard, give single Balancing Area Interconnections the flexibility to specify their own frequency-related requirements within a reasonable framework.

Response: Any Interconnection may request a variance with a NERC standard – the requirements for Interconnection-wide variances are outlined in the Reliability Standards Development Procedure.

2. Resolve the methodological concerns stated above in the development of BAAL limits, and others noted by Jaleeli that were omitted here for brevity.

Response: The drafting team believes that the methodology used to develop BAAL limits is working as intended and is as technically justified as practical. In the future, additional research may result in further refinement of the methodology used to develop these limits.

3. Take one or more of the following actions to assure that unscheduled net flows are bounded sufficiently, given the limitations noted in the proposed Balancing Standard: keep CPS 2; ratchet CPS 2 up by some value such as 25% per year, and back off the ratcheting process if problems arise; perform a simulation to determine what is the practical limit that should be established for a CPS 2 like criterion; retain the DCS with a 50% reporting threshold.

Response: Most stakeholders agree with retiring CPS2. CPS2 is not as effective as BAALs because under CPS2 entities have a 10 % ‘grace’ period per month during which they can operate outside bounds without regard to interconnection frequency – and CPS2 does not limit corrective actions to those that will actually support frequency.

Supplementary Comments from Hydro-Quebec TransEnergie's

Comments on Draft 7 of BAL-007-1 to BAL-011-1

Hydro-Quebec TransEnergie (HQTE) has always been operating as a single control area interconnection, connected asynchronously with the Eastern Interconnection through HVDC tie lines and converters. The concepts of having frequency trigger limits and abnormal limits as specified within the proposed Balancing Standard does not at all extrapolate well to HQTE and the imposition of their computation and use is unduly burdensome and counterproductive. This reality has inspired the single Balancing Area Interconnection alternative standard proposed below.

1. A single Balancing Area Interconnection may choose to deviate from BAL-007, BAL-008, BAL-009, BAL-010, and BAL-011, provided that the requirements stated herein are met.
2. The single Balancing Area Interconnection shall provide the NERC Resources Subcommittee or successor organization with a description of its first underfrequency relay setting for which load will be shed, along with an approximate time for which the limit would be violated before relay operation occurs.
3. The single Balancing Area Interconnection shall provide the NERC Resources Subcommittee or successor organization with a description of its first overfrequency relay setting for which generation will be disconnected, along with an approximate time for which the limit would be violated before relay operation occurs.
4. The single Balancing Area Interconnection shall provide the NERC Resources Subcommittee or successor organization with a description of any frequency deviation limits for which manual operations will be used to move frequency towards the scheduled frequency.
5. The single Balancing Area Interconnection shall provide the NERC Resources Subcommittee or successor organization with a description of frequency limits for which AGC will be suspended automatically.
6. The single Balancing Area Interconnection shall provide the NERC Resources Subcommittee or successor organization with a description of its time error correction procedure, and the method used for determining the scheduled frequency when time error correction is used.
7. The single Balancing Area Interconnection shall choose a sampling interval (e.g., one minute average), which will serve as a suitable reliability measure of its control performance.
8. The single Balancing Area Interconnection shall compute the following for each sampling interval: actual frequency, scheduled frequency, and frequency deviation from schedule.
9. The single Balancing Area Interconnection shall choose an appropriate statistical measurement technique for analyzing the frequency deviation from schedule data that is sampled as specified above. Standard deviation is the default methodology, but another more appropriate method can be requested and used if approved by the NERC Resources Subcommittee or its successor organization.
10. The single Balancing Area Interconnection shall establish a target for the monthly value of the statistical measure chosen for monitoring the control performance of its frequency

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deviation from schedule and provide this value to the NERC Resources Subcommittee or its successor organization.

11. The single Balancing Area Interconnection shall report its statistical control performance on a monthly basis by the 20th day after the end of a calendar month to its Compliance Monitor.
12. If the monthly target established as described above is exceeded in any month by more than 10%, an explanation identifying causes and the possible need for remedial action shall be provided.
13. The single Balancing Area Interconnection shall provide a list of underfrequency relay operations including date, time, duration, and MW magnitude of load loss, if any underfrequency relay operations occurred during a calendar month by the 20th day after the end of a calendar month to its Compliance Monitor.
14. The single Balancing Area Interconnection shall provide a list of overfrequency relay operations including date, time, duration, and MW magnitude of generation removed, if any overfrequency relay operations occurred during a calendar month by the 20th day after the end of a calendar month to its Compliance Monitor.
15. The single Balancing Area Interconnection shall retain the control performance and under/over frequency relay operation for at least 5 years.
16. The single Balancing Area Interconnection shall report all intended changes of the sampling interval, target, statistical method, relay settings, and time error correction procedure with at least 3 months of lead time to the NERC Resources Subcommittee or its successor organization.

Response: The drafting team cannot accept an alternate standard proposed in such a manner. If you want an Interconnection-wide Variance from a NERC standard you must follow the process identified in the Reliability Standard Development Procedure Manual.