Consideration of Comments on First Draft of Standard for Backup Facilities (Project 2006-04)

The Backup Facilities Standard Drafting Team thanks all commenters who submitted comments on the 1st draft of the Standard EOP-008-1. This standard was posted for a 30-day public comment period from February 7 through March 7, 2008. The standard drafting team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were 45 sets of comments, including comments from 127 different people from more than 75 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 has revised the standard for a second posting. Changes have been made to applicability and requirements R1.1, R1.2, R1.3, R1.4, R1.4.1, R1.4.2, R1.5, R1.6, R1.6.1, R1.6.2, R1.6, R3, R4, R5, R6, R7, R8, R8.1, R8.2, R9, R10, R11, and R12.

Major changes included:

- A revision to the applicability of the Transmission Operator (Section 4.1.2). This was done to attempt to eliminate the burden on a Transmission Operator that just has a radial connection to the BES under 200 kV unless the Regional Entity deems them as a critical part of the Interconnection.
- Changing the transition timeframes so that they are equivalent for all applicable entities. (R1.5)
- A short description of what needs to be in the Operating Process. (R1.6)
- A clarification to Requirements R4 and R5 as to when backup is required.

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 SAR can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Backup_Facilities.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 Vice President and 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 Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

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

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Crystal Musselman		x		x		x					
2.	Anita Lee (G7)	Alberta Electric System Operator		x								
3.	William J. Smith	Allegheny Power	x									
4.	Ken Goldsmith (G9)	ALTW				x						
5.	Jason Shaver	American Transmission Company	x									
6.	John Neagle (G13)	Associated Electric Coop., Inc.	x		x							
7.	Rich Hydzik (G16)	AVA	x		x							
8.	J. Andrew Dodge (G1)	Baltimore Gas & Electric	x									
9.	William Keagle (G1)	Baltimore Gas & Electric	x									
10.	Ed Carmen (G1)	Baltimore Gas & Electric	x									
11.	Dave Rudolph (G9)	BEPC	x		x		x	x				
12.	Terry Doern	Bonneville Power Administration	x		x		x	x				
13.	Brent Kingsford (G7)	California ISO		x								
14.	John Appel	Chelan County PUD	x		x		x	x			x	
15.	Paul Lampe (G15)	City Power & Light (Independence, MO)	x		x		x					
16.	Greg Tillitson (G16)	CMRC										x
17.	Eduardo Paredes González	Comision Federal de Electricidad	x		x		x	x				
18.	Peter Yost (G10)	ConEd	x			x	x	x				
19.	Jeanne Kurzynowski (G8)	Consumers Energy Company			x	x	x					
20.	Paul Morland (G16)	CSU	x		x							
21.	Jalil Babik (G2)	Dominion Resources			x		x					
22.	Louis Slade (G2)	Dominion Resources			x		x					
23.	Ronald E. Hart (G2)	Dominion Resources			x		x					
24.	Ronald Hart (G10)	Dominion Resources, Inc.					x					
25.	Jack Kerr (1) (G13)	Dominion Virginia Power	x									
26.	Daniel Herring (G3)	DTE Energy			x	x	x					
27.	Don Boyer (G3)	DTE Energy — Merchant Operations			x	x	x					

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			1	2	3	4	5	6	7	8	9	10
28.	Greg Rowland	Duke Energy	x		x		x	x				
29.	Sam Holeman (G13)	Duke Energy – Carolinas	x		x							
30.	Brian Berkstresser (G15)	Empire District Electric	x		x		x					
31.	Will Franklin (G4)	Entergy — System Planning						x				
32.	Jerry Stout (G4)	Entergy — System Planning						x				
33.	Edward J. Davis	Entergy Services, Inc.	x									
34.	Jim Case (G13)	Entergy Services, Inc.	x		x							
35.	Steve Myers (G7)	ERCOT		x								
36.	Sam Ciccone (G5)	FirstEnergy Corp.	x		x		x	x				
37.	Dave Folk (G5)	FirstEnergy Corp.	x		x		x	x				
38.	John Reed (G5)	FirstEnergy Corp.	x		x		x	x				
39.	Eugene Blick (G5)	FirstEnergy Corp.	x		x		x	x				
40.	John Stephens (G5)	FirstEnergy Corp.	x		x		x	x				
41.	Steve Lux (G5)	FirstEnergy Corp.	x		x		x	x				
42.	Bob Chambers (G5)	FirstEnergy Corp.	x		x		x	x				
43.	Mark L. Bennett	Gainesville Regional Utilities					x				x	
44.	Joseph Knight (G9)	GRE	x		x		x	x				
45.	Alessia Dawes	Hydro One Networks, Inc.	x		x							
46.	David Kiguel (G10)	Hydro One Networks, Inc.	x		x							
47.	Roger Champagne (G6) (G10)	Hydro-Québec TransÉnergie	x									
48.	Danielle Beaudry (G6)	Hydro-Québec TransÉnergie	x									
49.	Sylvain Clermont (G10)	Hydro-Québec TransÉnergie	x	x								
50.	Ron Falsetti (I) (G7)	Independent Electricity System Op.		x								
51.	Biju Gopi (G10)	Independent Electricity System Op.		x								
52.	Kathleen Goodman (I) (G10)	ISO New England		x								
53.	Matt Goldberg (G7)	ISO New England		x								
54.	Jim Cyrulewski (G8)	JDRJC Associates								x		
55.	Scott Frink (G15)	Kansas City Power & Light Co.	x		x		x					
56.	Mike Lucas (G15)	Kansas City Power & Light Co.	x		x		x					
57.	Eric Ruskamp (G9)	Lincoln Electric System	x		x		x	x				
58.	Donald E. Nelson (I) (G10)	MA Depart. of Public Utilities									x	
59.	Joseph DePoorter (I) (G9)	Madison Gas and Electric				x						
60.	Doug Rempel	Manitoba Hydro Energy Board	x		x		x	x				
61.	Robert Coish (G9)	Manitoba Hydro Energy Board	x		x		x	x				
62.	Tom Mielnik (G9)	MEC	x		x		x	x				
63.	Bill Phillips (G7)	Midwest ISO		x								

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64.	Jason L. Marshall (G8)	Midwest ISO		x								
65.	Terry Bilke (G9)	Midwest ISO		x								
66.	Carol Gerou (G9)	Minnesota Power	x		x		x	x				
67.	Larry Brusseau (G9)	MRO										x
68.	Michael Brytowski (G9)	MRO NSRS										x
69.	Jerry Tang (G13)	Municipal Electric Authority of GA	x		x							
70.	Michael Ranalli (G10)	National Grid	x			x						
71.	Tony Eddleman	Nebraska Public Power District	x		x		x					
72.	Randy MacDonald (G10)	New Brunswick System Operator		x								
73.	Jim Castle (G7)	New York ISO		x								
74.	Gregory Campoli (G10)	New York ISO		x								
75.	Ralph Rufrano (G10)	New York Power Authority	x			x	x	x			x	
76.	Guy V. Zito (G10)	Northeast Power Coordinating Council										x
77.	Lee Pedowicz (G10)	Northeast Power Coordinating Council										x
78.	Rick White	Northeast Utilities	x									
79.	Murale Gopinathan (G10)	Northeast Utilities	x			x						
80.	Julie Reichle (G16)	NWMT	x		x							
81.	Mike McGowan (G16)	NWMT	x		x							
82.	Diane Barney	NY State Dept. of Public Service									x	
83.	Stan Southers/Ellis Rankin	Oncor Electric Delivery Company	x									
84.	Brian Gooder (G10)	Ontario Power Generation, Inc.					x					
85.	Tim Lyons (G13)	Owensboro, KY Municipal Utilities	x		x							
86.	Robert Williams	PacifiCorp Grid Operations	x									
87.	Lauri Jones	Pacific Gas & Electric Company	x		x							
88.	Patrick Brown (G7)	PJM Interconnection		x								
89.	Patrick Brown (G11)	PJM Interconnection		x								
90.	Joe Willson (G11)	PJM Interconnection		x								
91.	Mike Bryson (G11)	PJM Interconnection		x								
92.	Al DiCaprio (G11)	PJM Interconnection		x								
93.	Phil Riley	PS Commission of South Carolina									x	
94.	Mark C. Wills	Sacramento Municipal Utility Dist.	x		x		x	x				
95.	Terry Blackwell (G12)	Santee Cooper	x									
96.	Wayne Ahl (G12) (G13)	Santee Cooper	x									
97.	Glenn Stephens (G12) (G13)	Santee Cooper	x									
98.	Tom Abrams (G12)	Santee Cooper	x									
99.	René Free (G12)	Santee Cooper	x									
100.	Wayne Guttormson (G9)	SaskPower	x		x							x

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101.	Pat Huntley (G13)	SERC Reliability Corporation										x
102.	John Troha (G13)	SERC Reliability Corporation										x
103.	Jay Campbell	Sierra Pacific Power Company	x									
104.	Rich Salgo	Sierra Pacific Resources Transm.	x									
105.	Roman Carter (G13) (G14)	Southern Company Services, Inc.	x		x							
106.	J.T. Wood (G14)	Southern Company Services, Inc.	x									
107.	Marc Butts (G14)	Southern Company Services, Inc.	x									
108.	Steve Corbin (G14)	Southern Company Services, Inc.	x									
109.	Shane Eaker (G14)	Southern Company Services, Inc.	x									
110.	Rodney O'Bryant (G14)	Southern Company Services, Inc.	x									
111.	David Harris (G14)	Southern Company Services, Inc.	x									
112.	Mike Sanders (G14)	Southern Company Services, Inc.	x									
113.	Charles Yeung (G7)	Southwest Power Pool		x								
114.	Robert Rhodes (G15)	Southwest Power Pool										x
115.	Kyle McMenamin (G15)	Southwestern Public Service	x		x		x					
116.	Stephen Joseph	Tampa Electric Company	x		x		x					
117.	Larry Rodriguez (G13)	Union Power Partners					x					
118.	Brian Evans-Mongeon (G10)	Utility Services, LLC						x				
119.	Jim Haigh (G9)	WAPA	x					x				
120.	Ed Hulls (G16)	WAPA	x		x							
121.	Nick Zaber (G16)	WAPA	x		x							
122.	Barb Kedrowski (G8)	We Energies			x	x						
123.	Steve Ashbaker (G16)	WECC										x
124.	Steve Rueckert (G16)	WECC										x
125.	Allen Klassen (G15)	Westar Energy	x		x		x					
126.	Neal Balu (G9)	WPS			x	x	x	x				
127.	Pam Oreschnick (G9)	Xcel Energy Services, Inc.	x		x		x	x				
128.	Terri Eaton	Xcel Energy Services, Inc.	x		x		x	x				

I – Individual
G1 – Baltimore Gas & Electric
G2 – Dominion Resources Services, Inc.
G3 – Duke Energy
G4 – Entergy – System Planning & Operations

G5 – FirstEnergy Corp.
G6 – Hydro-Québec TransÉnergie
G7 – ISO/RTO Council Standards Review Committee
G8 – Midwest ISO
G9 – Midwest Reliability Organization
G10 – NPCC Regional Standards Committee
G11 – PJM Interconnection
G12 – Santee Cooper
G13 – SERC OC Standards Review Group
G14 – Southern Transmission
G15 – SPP Operating Reliability Working Group
G16 – WECC Reliability Coordination Comments Work Group

Index to Questions, Comments, and Responses

1. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

Summary Consideration: After reading the comments for Question #1, there appeared to be some confusion as to what the SDT was asking. Some commenters seemed to think the SDT was asking whether all TOPs should be excluded from this standard. That was definitely not the case. Rather, the SDT was asking if the industry agreed with the Critical Asset/IROL exclusion criteria included in Section 4.1.2 which would potentially exclude a limited number of TOPs from compliance with this standard. There were also a number of commenters that understood the SDT's question and clearly addressed it. In response to the overwhelming majority of the comments expressing concern regarding the exclusion criteria, the SDT has decided to remove the IROL/Critical Asset exclusion criteria for TOPs. Instead, we propose to replace the IROL/Critical Asset exclusion criteria with language that is intended to require only those TOPs who operate Transmission Facilities that will have a material impact on reliability of the Bulk Electric System. The language shown below identifies the TOPs that would be required to comply with the standard:

4.1.2 Transmission Operator operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES).

By including this new language in Section 4.1.2 of the standard this will require all entities registered as a TOP that have a material impact on the Bulk Electric System to have back-up functionality that ensures it has the same capability as it does with its primary facility and also the ability to remain in compliance with all with applicable reliability standards. However, if a Regional Entity/NERC demonstrates that an excluded TOP does have a material impact on the Bulk Electric System, then that TOP would have to comply with this standard.

Some commenters agreed that smaller TOPs may not need the same back-up functionality as larger TOPs. While the SDT has proposed new language for determining which TOPs must comply with this standard, it is also possible to further address these issues in the registration process and possibly through a revision to the Functional Model.

Some commenters referenced issues related to local control centers (LCCs) that are not registered with NERC as a TOP. Since the TOP is the registered entity, it is responsible for its compliance, and that of the LCCs under it, with standards that are applicable to it under the TOP function. The SDT is confident that we have addressed this issue as much as we can in the standards development process in Requirement R3 of the draft standard. If there are still issues related to what an LCC and its registered TOP are required to comply with, this is best handled in the registration process and possibly through a revision to the Functional Model, and not through the standards development process.

In summary, this standard would require RCs to have a full back-up facility, and BAs and applicable TOPs to have full back-up functionality.

#1 – Commenter	Yes	No	Comment
Allegheny Power		x	All control centers (Generator Operator or Transmission Owner (LCC) that control facilities via an EMS, GMS, etc. should comply with a Backup Facility criteria. That criteria may be in the form of a NERC Standard or a set of RTO/ISO requirements. In the case where a set RTO/ISO requirements are

#1 – Commenter	Yes	No	Comment
			used for control centers that are not Transmission Operators, those requirements should meet a minimum criteria established in a NERC Standard to guarantee uniformity on Bulk Electric System.
Entergy – System Planning		x	The attempt to limit the Transmission Operators subject to this standard opens many more questions and issues that are not addressed. The argument could also be made by some BAs that they have no critical assets or other reliability impact and thus desire an exclusion.
Hydro Québec/TransÉnergie		x	This standard should apply to all RCs, BAs, and TOPs. If an entity is registered as a TOP, their transmission system is part of the BES. The intent of providing backup facilities is to ensure the BES continues to be controlled and monitored.
IESO ISO New England ISO/RTO Council		x	This standard should apply to all RCs, BAs, and TOPs as the requirements so stipulate. We are therefore unclear on the basis of this question. The intent of providing backup capability/facilities is to ensure the BES continues to be controlled and monitored to balance load-generation-interchange, maintain frequency within acceptable range and loading on transmission network within SOLs and IROLs. BA, TOP and RC are the operating entities that are responsible for these tasks and hence must provide backup facilities to ensure continued control and operation. However, if the question is to address the specific provision in the Applicability Section, viz: "Transmission Operator with control of Facilities that are designated as Critical Assets or with defined Interconnection Reliability Operating Limits (IROLs).", then our comment would be that the provision should stops at "Critical Assets" since R1.2 in CIP-002-1 clearly stipulates that Critical Assets are those needed to support the reliable operation of the BES, which generally includes monitoring and operating to within IROLs and SOLs. Tying the provision to "with defined IROLs" would allow TOPs that monitors and control SOLs, and deploy/operate BES facilities that could affect BES reliability to be excluded from this standard, which in our view is unacceptable since SOL could become IROL any time as system conditions change.
Madison Gas and Electric		x	This standard should apply to all RCs, BAs, and TOPs. Any loss of primary control center may have a hugh effect on the BES. All TOPs should be required and if they believe they should not be, then the TOP should request

#1 – Commenter	Yes	No	Comment
			a waiver from NERCie, if the TOP only had a small radio fed transmission system.
Manitoba Hydro Energy Board		x	The TOP is as responsible as any entity in operating the BES, therefore their facilities are as important to the reliable operation of the BES as an RC or BA. I fail to see how the applicability is limited by the statement in the applicability section 4.1.2, any TOP with an EMS/SCADA system has critical assets and needs to protect against the loss of those assets.
Midwest ISO		x	This standard should apply to all RCs, BAs, and TOPs. If an entity is registered as an TOP, their transmission system is part of the BES. Any part of the BES could become limited by an IROL under certain conditions. Furthermore, these entities are responsible for identifying their own Critical Assets and IROLs. Thus, this is equivalent to letting a given TOP decide if a standard applies to them. Letting a responsible entity determine if a standard applies to them is a form of self-regulation. This is really a registration issue that should be determined by the Regional Entities. If the RE determines an entity meets the TOP registration criteria, then that entity should be subject to the same standards as any other TOP.
Midwest Reliability Organization		x	No, according to the NERC glossary of terms the transmission operator is that "… entity (which is responsible) for reliability of its "local" transmission system, and that operates or directs the operation of the transmission facilities." Taking this into account, this standard speaks to the lost of these transmission facilities and how the transmission operator plans to handle these lost facilities. All transmission operators which operate Bulk Electric System should be applicable to this standard since bulk electric facilities, systems, and equipment which if destroyed, degraded, or otherwise rendered unavailable would affect the reliability or operability of the BES since the BES would no longer be capable of functioning. (Also, please note I am not referring to the lost of one transmission line or a generator but a loss of an entire "local" transmission system operated by a transmission operator.) Is it possible for a transmission operator to operate a transmission facility which is not included in the BES? If so, then perhaps this standard should not apply to them. Please give an example of a transmission operator who does not operate BES facilities?
PJM Interconnection		x	According to NERC's Statement of Compliance Registry Criteria (Revision 4.0), any entity responsible for the reliability of its "local" transmission

#1 – Commenter	Yes	No	Comment
			system, and that operates or directs the operations of the transmission facilities, and is directly connected to the bulk power system (>100 kv), is required to register as a TOP. As such, the loss of any TOP's primary control facilities could have a major impact on wider system reliability. Therefore, ALL registered TOPs should be included in this standard.
Sacramento Municipal Utility Dist.		x	All BES entities registered as TOPs should have the same requirements.
Response: After reading the comments for Question #1, there appeared to be some confusion as to what the SDT was asking. Some commenters seemed to think the SDT was asking whether all TOPs should be excluded from this standard. That was definitely not the case. Rather, the SDT was asking if the industry agreed with the Critical Asset/IROL exclusion criteria included in Section 4.1.2 which would potentially exclude a limited number of TOPs from compliance with this standard. There were also a number of commenters that understood the SDT's question and clearly addressed it. In response to the overwhelming majority of the comments expressing concern regarding the exclusion criteria, the SDT had decided to remove the IROL/Critical Asset exclusion criteria for TOPs. Instead, the SDT has proposed to replace the IROL/Critical Asset exclusion criteria with language that is intended to require only those TOPs who operate Transmission Facilities that will have a material impact on reliability of the BES. The language shown below identifies the TOPs that would be required to comply with the standard: 4.1.2. Transmission Operator operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES). By including this new language in Section 4.1.2 of the standard, this will require all entities registered as a TOP that have a material impact on the BES to have back-up functionality that ensures it has the same capability as it does with its primary facility and also the ability to remain in compliance with all with applicable reliability standards. However, if a Regional Entity/NERC demonstrates that an excluded TOP does have a material impact on the BES, then that TOP would have to comply with this standard. Some commenters agreed that smaller TOPs may not need the same back-up functionality as larger TOPs. While the SDT has proposed new language for determining which TOPs must comply with this standard, it is also possible to further address these issues in the registration process and possibly through a revision to the Functional Model. In summary, this standard would require RCs to have a full back-up facility, and BAs and applicable TOPs to have full back-up functionality.			
American Transmission Company		x	ATC does not understand the SDT's motivation for limiting the scope of the proposed Standard to Transmission Operators (TOPs) with control of Facilities that are designated as Critical Assets or with defined Interconnection Reliability Operating Limits. The proposed accountability is a step backward from existing Reliability Standards and has the potential to expose the grid to greater reliability related risks following the loss of a non-applicable TOP's control center.

#1 – Commenter	Yes	No	Comment
			What justification does the SDT provide to make such a major change to this reliability standard?
Response: In response to the overwhelming majority of the comments expressing concern regarding the exclusion criteria, the SDT had decided to remove the IROL/Critical Asset exclusion criteria for TOPs. Instead, the SDT proposes to replace the IROL/Critical Asset exclusion criteria with language that is intended to require only those TOPs who operate Transmission Facilities that will have a material impact on reliability of the BES. The language shown below identifies the TOPs that would be required to comply with the standard: 4.1.2. Transmission Operator operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES).			
Baltimore Gas and Electric		x	Under the Applicability Section 4.1.2; What is the official definition of "Critical Assets"? Are these the same as the Critical Assets identified in the CIP-002? There are situations where the Transmission Operators and the Transmission Owners are not the same entitiy. In this case, the Transmission Owner is responsible for identifying their Criitical Assets under CIP-002 and there is no requirement that they share this list with their Transmission Operator. In this relationship, how would the Transmission Operator know what the Critical Assets are in their transmission zone? Does the statement "with control of Facilities that are designated as Critical Assets" imply that this standard does not apply to Transmission Operators that do not have physical control of Facilities that are designated as Critical Assets? As written, this standard would not apply to Transmission Owners who perform the Local Control Center function under the direction of a NERC registered Transmission Operator (although the LCC may actually control the facility designated as critical or associated with the IROL).
Bonneville Power Admin.	x		If TOs have IROLs they must have the capablity to monitor critical lines & transmission paths within critical time periods (20 minute for stability, 30 minutes for thermal). This may add the need for B/U control center. Many smaller TOs with limited tranmission do not impact the BES.
Duke Energy Corp.		x	The limitation doesn't make sense and would be difficult to enforce, since Critical Asset lists and defined IROLs will change over time. Applicability should be on the basis of NERC Registration, to avoid an ongoing tangled

#1 – Commenter	Yes	No	Comment
			mass of exceptions. For example, a TOP with control over a limited number of facilities should still be required to provide backup functionality, however backup functionality can be provided in other ways than constructing backup facilities.
Gainesville Regional Utilities		x	In some cases an entity categorized as a transmission operator may be an entity that has a radial transmission line through their system and there is no nee for either a control center or a back up. They still need a back up plan.
Santee Cooper	x		While we agree, we also believe that this standard may not be the best place to provide for that limitation. Other processes exist to handle exceptions and there may be a more reasonable way to limit the impact to smaller Transmission Operators (TOPs). This could easily be handled in the rules of registration for TOPs.
Sierra Pacific Resources Transm.	x	x	I agree with the concept of limiting the applicability, but I disagree with the relationship made to "Critical Assets", which I assume are those that are determined pursuant to CIP-002. Given the wide industry debate about CIP Critical Assets, I don't believe this will be a stable enough parameter upon which to base the need for BUCC's. As an alternative, perhaps the restriction should be to "TO's with control of Facilities with defined IROL's or SOL's".
SPP ORWG		x	We do not agree with the wholesale exclusion of all TOPs without Critical Assests or IROLs from the requirement of maintaining some semblance of backup functionality. We believe they should at a very minimum be required to maintain communication with their Reliability Coordinator. Therefore provisions should be made in the standard to include such a requirement. Relatedly, should the SDT give consideration to an exclusion for small BAs?

Response: In response to the overwhelming majority of the comments expressing concern regarding the exclusion criteria, the SDT had decided to remove the IROL/Critical Asset exclusion criteria for TOPs. Instead, the SDT proposes to replace the IROL/Critical Asset exclusion criteria with language that is intended to require only those TOPs who operate Transmission Facilities that will have a material impact on reliability of the BES. The language shown below identifies the TOPs that would be required to comply with the standard:

4.1.2. Transmission Operator operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES).

By including this new language in Section 4.1.2 of the standard this will require all entities registered as a TOP that have a material impact on the BES to have back-up functionality that ensures it has the same capability as it does with its primary facility and also the ability to remain in compliance with all with applicable reliability standards. However, if a Regional Entity/NERC demonstrates that an excluded TOP does have a

#1 – Commenter	Yes	No	Comment
material impact on the BES, then that TOP would have to comply with this standard. Some commenters agreed that smaller TOPs may not need the same back-up functionality as larger TOPs. While the SDT has proposed new language for determining which TOPs must comply with this standard, it is also possible to further address these issues in the registration process and possibly through a revision to the Functional Model. Some commenters referenced issues related to local control centers (LCCs) that are not registered with NERC as a TOP. Since the TOP is the registered entity, it is responsible for its compliance, and that of the LCCs under it, with standards that are applicable to it under the TOP function. The SDT is confident that we have addressed this issue as much as we can in the standards development process in Requirement R3 of the draft standard. If there are still issues related to what an LCC and its registered TOP are required to comply with, this is best handled in the registration process and possibly through a revision to the Functional Model, and not through the standards development process.			
Dominion Virginia Power Dominion Resources Entergy SERC OC Standards Review Group		x	Dominion Virginia Power (DVP) believes that requirement 4.1.2, as written, is unenforceable and unmeasurable. There may be a more reasonable way to limit the impact to smaller Transmission Operators (TOPs). This could easily be handled in the rules of registration for TOPs. Alternatively ,there is a process to request waivers from NERC standards that could be used to solve this issue.
DTE Energy		x	I do not agree with this limitation. I would agree with this aproach if there was one risk-based assessment methodology used by all Transmission Operator entities to identify their Critical Assets.
FirstEnergy Corp.		x	We do not agree with the limitations proposed in the applicability. We see the following reliability issues with these limitations: 1. It leaves it to the TOP to determine if the standard applies to him. The burden of determining applicability to these requirements should be the responsibility of the auditor. 2. If a TOP incorrectly determines that he is not responsible to have plans for backup functionality, his neighbors in the BES control system may be in jeopardy. 3. If an entity is registered as a TOP, then every standard applies to him since his registration has already determined he has impact on the reliability of the Bulk Electric System.
Southern Company Services, Inc.		x	Southern Company: Southern believes that requirement 4.1.2, as written, is unenforceable and unmeasurable. A more reasonable way to limit the impact

#1 – Commenter	Yes	No	Comment
			to smaller Transmission Operators (TOPs) might be for them to request a waiver to the standard through NERC's waiver process. Southeastern RC comment: Without the TOP and BA, the function of the RC ceases to exist. All physical control of the Bulk Electric System ceases to exist without a TOP or BA in place. The RC does not have physical controls of the grid. The TOP and BA can function and maintain reliability without the existence of a RC.
Response: In response to the overwhelming majority of the comments expressing concern regarding the exclusion criteria, the SDT had decided to remove the IROL/Critical Asset exclusion criteria for TOPs. Instead, we propose to replace the IROL/Critical Asset exclusion criteria with the language that is intended to require only those TOPs who operate transmission facilities that will have a material impact on reliability of the bulk power system. The language shown below identifies the TOPs that would be required to comply with the standard: Transmission Operator operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES). By including this new language in 4.1.2 of the standard this will require all entities registered as a TOP that have a material impact on the bulk power system to have back-up functionality that ensures it has the same capability as it does with its primary facility and also the ability to remain in compliance with all with applicable reliability standards. However, if a Regional Entity/NERC demonstrates that an excluded TOP does have a material impact on the bulk power system, then that TOP would have to comply with this standard.			
Avista Corporation			No comment.
Chelan County PUD	x		
Comision Federal de Electricidad WECC Operating Practices SC	x		As long as the requirements in this standard are applicable to any transmission operator whose systems can impact reliability of the BES and not just registered TOPs.
Hydro One Networks, Inc.	x		
MA Dept. of Public Utilities			No comment.
Nebraska Public Power District	x		
NY State Dept. of Public Service			No comment.
Northeast Utilities	x		
NPCC Regional Standards Cmte.			No comment.

#1 – Commenter	Yes	No	Comment
Oncor Electric Delivery Company	x		
PacifiCorp	x		
Pacific Gas and Electric Company	x		
PS Commission of South Carolina	x		
Sierra Pacific Power Company	x		
Tampa Electric Company	x		
Xcel Energy	x		
Response: Thank you for your comment. Note that in response to comments from other stakeholders, the SDT has revised the applicability section of the standard. Please see the Summary Consideration for this question.			

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

Summary Consideration: Care has been taken to consider and include comments on the original EOP-008-0 submitted by various industry groups as well as FERC from Order 693. However, the SDT does not feel that any reliability purpose would be served by including GOP's as applicable entities.

The primary issue of whether *centrally dispatched generation control centers* should be applicable entities to the EOP-008-1 standard is an issue of risk exposure to the reliable operation of the BES. The SDT believes the risk exposure does not merit the inclusion of GOP's in this standard for the following reasons:

1. The risk exposure for the loss of an RC's, BA's, or TOP's primary control center is far greater than for the loss of any one *centrally dispatched control center*. This greater risk is a function that each RC, BA, and TOP controls a definitive portion of the interconnection. The interconnection requires the command and control directives and signals from each RC, BA, and TOP to synchronize minute-to-minute operations within these operational zones. And when these RC, BA, and TOP control centers are lost, the key outputs of directives and communications are lost within that zone. In contrast, if GOPs operating generators from a *centrally dispatched generation control center* were to have to evacuate their control centers, the key output of energy from their controlled units is not lost. With the energy still being produced by the units there is no DCS event because a *centrally dispatched generation control* center is evacuated. Understandably, in some cases the directives and communications that permit load following capability of those units may be lost, but in other cases through direct data pathways and communication protocols between BA's and generating units there would not be a significant impact to unit load following and ancillary service operations.

2. In the case where the BA may not have the data links and communication protocols to sustain load following from the units being controlled by a compromised *centrally dispatched generation control center*, the BA should be able to quickly assess that it had some units no longer following dispatch signals. At that point, the BA needs to handle this situation as it does similar situations each day when units are slow to respond, fail to start, or for one reason or another fail to follow control signals. In such a case, the BA goes to the next set of resources under its control and directs them to fill the void. So in contrast to where a TOP and BA have only one RC to turn to for RC directives, a BA or TOP could look to any number of GO's and GOP's to resolve a BES operating issue. As such, the SDT saw the mitigation of this risk as really an economic issue (moving to the next marginal unit) rather than an operating emergency.

3. Additionally, the risk created by the potential loss of a *centrally dispatched generation control center* is further mitigated by the all too typical situation that such GOPs operate units throughout the interconnection in multiple BAs. As such, the risk is spread amongst multiple BAs and TOPs each of which have their own diverse selection of alternative GOs and GOPs to address the potential operating issue.

An additional reason for why the SDT has not included *centrally dispatched generation control centers* into the applicability of this standard is that there is no such defined role in the NERC Functional Model. The SDT grappled with whether a *centrally dispatched generation control center* might be an entity that controlled a particular percentage of any one BA's designated resources (how is that tracked?), or controlled enough assets to have a particular impact to the BES's frequency (but at what dispatch point?). Bottom-line: there are far too many permutations of what a *centrally dispatched generation control* center could be. The end result of including such an ill-defined term into the applicability of EOP-008-1 is that too easily plants with multiple units at a single station might suddenly have to become compliant to this standard where in many cases the physical controls in their control rooms would be hard to replicate at an off-site facility.

The SDT believes strongly that a combination of the strengthening of requirements for RCs, TOPs, and BAs in the revised EOP-008-1 (see draft standard) as well as requirements in other, existing standards, adequately and sufficiently address the issue of GOP accountability.

Conclusion:

The SDT is recommending not to include GOPs in this list of applicable Responsible Entities, even those with centrally dispatched generation control centers, as adequate and sufficient concerns for the reliability of the BES are met within this and other standards and the exclusion of the GOP in EOP-008-1 is not detrimental to reliability or maintaining situational awareness of the BES. To include the GOP as an applicable entity in EOP-008-1 would not promote reliability and would simply create redundancy in the standards, a position that the NERC Reliability Standards Development Work Plan is striving to eliminate.

#2 – Commenter	Yes	No	Comment
Allegheny Power		x	See comment to question #1.
American Transmission Company		x	Generation is critical to the reliable operation of the BPS and should be included. ATC believes that the a more appropriate exemption could be based on the MW controlled by the GOP. ATC may be open to changing its position on this issue if strong information is presented to support this position.
Bonneville Power Admin.		x	A GOP must provide support to the BA to meet BAL standards during adverse power system conditions even when their primary control center is destroyed or not funcational. Other options may be practical as long as they meet the reliablity needs and meet NERC and regional standards.
DTE Energy		x	As energy markets mature and more generation assets are operated from central control centers, it is imperative for grid reliability, security, and stability that GOPs be able to fulfill their roles. Not having GOPs identified as applicable entities to a reliability standard addressing loss of control center functionality misses the intent of this standard.
Duke Energy Corp.		x	As FERC noted in Order No. 693, generator operators who have operational

#2 – Commenter	Yes	No	Comment
			control over significant amounts of generation are important to the reliability of the Bulk Power System. As such they should provide backup capabilities that are independent of the primary control center, can operate for a prolonged period of time, and provide for a minimum functionality to replicate the critical reliability functions of the primary control center. The reason BAs are required to have backup functionality is that BAs have direct communications (both data and voice) with generator sites and generator personnel. These are the front lines of operational situations. It is vital that we maintain these links in both normal, emergency conditions, and backup mode conditions.
FirstEnergy Corp.		x	We do not agree with the exclusion of a GOP with a centrally dispatched control center from the applicable entities in this standard. GOPs with responsibility for many units play an important role in the reliable operation of the BES. These GOPs should have business continuity plans. The bottom line is this: If it is a control center, and it has impact on the BES, it must be responsible for providing a way to backup its control center. We suggest adding the "Generator Operator" to the Applicability section of the standard, and adding "Generator Operator with centrally dispatched control centers" to requirements R1, R2, R5, and R7 through R13.
Gainesville Regional Utilities		x	
Midwest Reliability Organization		x	The SDT should include the Generator Operator within this standard especially if GOP can efficiently and effectively fulfill their role in preserving the reliability of the interconnection following the loss of the GOP's control center.
Sierra Pacific Power Company		x	To exempt GOP is a serious oversight for this standard. Specifically, for those GOP with a "centrally dispatched control center," they may control many stations with thousands of MW. If that central dispatch facilitiy were lost, how is interconnection reliability maintained without a backup control center? It's not.
Response: The SDT has considered these insights but has decided to continue to not have this standard applicable to "centrally dispatched generation control centers" for the reasons stated in the Summary Consideration for this question.			
Manitoba Hydro Energy Board		x	The GOP still needs to have a plan to continue its operations should they loose control centre functionality. The GOP may not be required to meet every requirement in the standard but they should have a plan to continue operations as per Requirement 1.
Midwest ISO		x	Standards are not supposed to define the "how" but rather they are supposed to define the "what". The SDT is focused on the "how". Within this very

#2 – Commenter	Yes	No	Comment
			question, the SDT acknowledges that there are other equally effective and efficienct methods for the GOPs to continue to fulfill their role in preserving reliability. We agree that is true, however, the SDT needs to define that role in preserving reliability. For instance, does the GOP need to have a plan to continue to dispatch the units in the event their central dispatch office fails? That plan could involve a number of solutions but the role is a focused on "what" needs to be accomplished.
PJM Interconnection	x		Although GOPs should not be required to maintain backup facilities, they should be required to have a backup communications plan under the COM standards.
Sacramento Municipal Utility Dist.		x	The Centrally controlled GOPs have to have a plan to operate if they lose their central control center. The impact to the BES could be the same as for a TOP.
WECC Operating Practices Subc.		x	The Centrally controlled GOPs have to have a plan to operate if they lose their central control center.
Response: The SDT has considered these insights but has decided to continue to not have this standard applicable to "centrally dispatched generation control centers" for the reasons stated in the Summary Consideration for this question.			
Pacific Gas and Electric Company		x	It is our understanding that the drafting teams are given specific direction in following the FERC Order 693 directive. If this approach had been followed then the team would respond to industry comments during the comment review period. This approach will further delay the standard implementation period.
Response: The SDT has tried to follow all of FERC's directives in its approach and has even spoken with FERC on this issue. It was the SDT's intent to explore other options with the broad base of the industry in the hopes of better addressing FERC's directives by asking this question. The SDT believes that the latest draft of EOP-008-1 and this comment report will help address FERC's concerns.			
SPP ORWG		x	We believe that as a bare minimum GOPs that have a significant impact (total output of 100 MW or more) on the BES should be requried to maintain communications with its host BA.
Response: The SDT believes that communication requirements should, and will, be handled in updated communications standards.			
Avista Corporation			No comment.
Baltimore Gas and Electric			No comment.
Chelan County PUD	x		Our generation facilities do have procedures for maintaining operations in the event of a loss of control system functionality, however this does not involve relocating to different facilities.
Comision Federal de Electricidad	x		

#2 – Commenter	Yes	No	Comment
Dominion Resources	x		In Order 693, FERC stated that the goal of the Reliability Standard is the continuation of reliable operations and the maintenance of situational awareness in the event that the primary control center is no longer operational. They further stated that "Other entities, including balancing authorities, transmission operators and centrally dispatched generation control centers, must provide for the minimum backup capabilities discussed above but may do so through other means, such as contracting for these services instead of through dedicated backup control centers." Given that the impact to reliability can vary depending on many diverse factors including; size of owner's asset base, NERC region, ISO/RTO or market rules, etc. we support the standard as written. Each region can, through its standards development process, place additional requirements if it deems necessary. Each RTO/ISO or market, through its stakeholder process, can also impose additional requirements upon its participants if it deems necessary. We further state that we support comments submitted by the SERC Operating Committee Standards Review Group (SOCSRG).
Dominion Virginia Power (1)	x		DVP agrees with this approach. Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). DVP believes that this standard does not need to apply to Generator Operators (GOP) with a central dispatch function as long as there are no gaps in the Reliability Function's ability to communicate with generation assets. Other reasons for not including GOP's in this standard are: 1.) the diverse nature and sheer number of generators, each already required to contribute to system reliability deficiencies (e.g., AVR response), as opposed to having only one Reliability Coordinator control room, for example. Any reliability deficiency caused by the loss of any single GOP control room or plant would simply be "made up" by other GOPs in the area. 2.) the various contributions to the Bulk Electric System of each generator must be taken into account. Some generators run when commercially contracted, others provide imbalance and regulation services, some are contracted to be "Must Run" units, yet others provide peaking capabilities. A "One Size Fits All" approach to requiring GOP BUCCs suggests inefficient and ineffective reliability requirements, and

#2 – Commenter	Yes	No	Comment
			3.) the "hands on" nature of large (500+MW) generating plants essentially prevents operation from a remote location.
Entergy	x		Entergy agrees with and supports the SOCRG comments. The SOCSRG agrees with this approach. Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). The SOCSRG believes that this standard does not need to apply to Generator Operators (GOP) with a central dispatch function as long as there are no gaps in the Reliability Function's ability to communicate with generation assets. Other reasons for not including GOP's in this standard are: 1.) the diverse nature and sheer number of generators, each already required to contribute to system reliability deficiencies (e.g., AVR response), as opposed to having only one Reliability Coordinator control room, for example. Any reliability deficiency caused by the loss of any single GOP control room or plant would simply be "made up" by other GOPs in the area. 2.) the various contributions to the Bulk Electric System of each generator must be taken into account. Some generators run when commercially contracted, others provide imbalance and regulation services, some are contracted to be "Must Run" units, yet others provide peaking capabilities. A "One Size Fits All" approach to requiring GOP BUCCs suggests inefficient and ineffective reliability requirements, and 3.) the "hands on" nature of large (500+MW) generating plants essentially prevents operation from a remote location
Entergy – System Planning	x		It appears to be appropriate to exclude centrally dispatched control centers for generators if they do not perform the functions of or part of the functions of a BA. The means for executing dispatch for a unit is a business decision If the dispatch operator is not performing any BA functions then there is no need for this standard to apply and whatever other standards or rules for maintaining communication between the unit and BA would apply.
Hydro One Networks, Inc.	x		We agree, assuming that for each Generation Station (GS), a GOP normally dispatches using a central control centre and a local control centre is located at the GS.
Hydro Québec/TransÉnergie NPCC Regional Standards	x	x	The applicability of this standard should be restricted to RC, BA, and TOP functions. The GOP's functions is to follow the directions of the BA for demand-

#2 – Commenter	Yes	No	Comment
Cmte.			energy balance and to ensure that applicable standards are complied to. It is essential that the BA, TOP, and RC have back-up facilities or provisions as specified in this standard but the GOP need not be included as long as the BA ensures that all BA functions are addressed by its back-up facilities. However, it is important that GOPs have a backup communication plan in place which must be provided to the appropriate reliability entity upon request.
IESO ISO New England	x		We agree that there are other equally effective and efficienct methods for the GOPs to continue to fulfill their obligation to generate, may it be for commercial reasons or reliability reasons. Generally speaking, the GOPs follow instructions of the BA, who is responsible for generation-load-interchange balance and maintaining system frequency. We agree that the standard does not need to include GOPs but the reasoning is that the BA will ensure dispatch instruction is provided to the GOPs to meet reliability standards. We recognize that some GOPs elect to set up control centres to operate a group of generators but this is a process set up for business efficiency only. Loss of a GOP operating centre does not hamper the capability of a BA communicating dispatch instructions directly to the generator/generating plant for continuous operation. However, it is important that GOPs have a backup communications plan in place which must be provided to the appropriate reliability entity upon request.
ISO/RTO Council			No comment.
Madison Gas and Electric	x		
MA Dept. of Public Utilities			No comment.
Nebraska Public Power District	x		
NY State Dept. of Public Service			No comment.
Northeast Utilities	x		An individual generator should not impact the reliability of the BPS.
Oncor Electric Delivery Company	x		
PacifiCorp	x		

#2 – Commenter	Yes	No	Comment
PS Commission of South Carolina	x		
Santee Cooper	x		Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). As long as there are no restrictions in the ability to communicate with the GOPs, there should not be an issue.
SERC OC Standards Review Group	x		The SOCSRG agrees with this approach. Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). The SOCSRG believes that this standard does not need to apply to Generator Operators (GOP) with a central dispatch function as long as there are no gaps in the Reliability Function's ability to communicate with generation assets. Other reasons for not including GOP's in this standard are: 1.) the diverse nature and sheer number of generators, each already required to contribute to system reliability deficiencies (e.g., AVR response), as opposed to having only one Reliability Coordinator control room, for example. Any reliability deficiency caused by the loss of any single GOP control room or plant would simply be "made up" by other GOPs in the area. 2.) the various contributions to the Bulk Electric System of each generator must be taken into account. Some generators run when commercially contracted, others provide imbalance and regulation services, some are contracted to be "Must Run" units, yet others provide peaking capabilities. A "One Size Fits All" approach to requiring GOP BUCCs suggests inefficient and ineffective reliability requirements, and 3.) the "hands on" nature of large (500+MW) generating plants essentially prevents operation from a remote location.
Sierra Pacific Resources Transm.	x		The suggestion that Generating plants would need to have backup control centers is not financially feasible for the industry. The potential benefit of such a move would be minimal, if any. I'm pleased that the SDT did not pursue that direction.
Southern Company Services, Inc.	x	x	Southen Company: We agree with this approach. Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). The SOCSRG believes that this standard does not need to apply to Generator Operators

#2 – Commenter	Yes	No	Comment
			(GOP) with a central dispatch function. Southeastern RC comment: With a GOP having a centrally located dispatch control center, all control of the gernators are at one location. With the loss of this center and no backup facilties, the BA could not meet standards nor maintain reliability as the pure BA does not have physical control of the generators.
Tampa Electric Company	x		
Xcel Energy	x		XES agrees with the drafting team that there are other means to address loss of a centrally dispatched generation control center besides requiring the burden and expense of back-up facilities. In many if not most cases the applicable Balancing Authority is fully capable of dispatching generation units directly in the event a centrally dispatched generation control center becomes inoperable making a backup control center for the generation dispatch function unnecessary.
Response: Thank you for your response.			

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

Summary Consideration: Due to the questions raised, the SDT discussed the 2 hour timeframe at length and decided to retain it as described in the responses. One change was made to the requirements due to comments on this question:

R1.5 A transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running that is less than two hours.
R1.6: An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to get backup functionality up and running. The Operating Process shall include:
R1.6.1. A list of all entities that will be notified when there is a change in operating locations.
R1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary/backup functionality.
R6. ~~Each Reliability Coordinator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours.~~

#3 – Commenter	Yes	No	Comment
American Transmission Company		x	The proposed standard is weaker than the existing standard. ATC believes that the expected time should be one hour and, if exceeded, the plan should address how you are going to operate into the next hour. With a maximum time of 2 hours.

Response: There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons:

- The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it.
- If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden.
- Realistic expectations for travel time in emergency conditions between the 2 centers.
- 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers.
- It is assumed that the TOP and BA are still functioning and can operate on their own for a 2 hour time period.
- There is additional functionality required in this standard that wasn't there before.
- Organizational inertia in responding to the disaster.
- Cost benefit versus relative risk.
- R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability.

#3 – Commenter	Yes	No	Comment
• It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
Chelan County PUD		x	2 hours is a long time to be without a Reliability Coordinator function in the case of an emergency. I believe WECC plans to have the two Reliability Coordinators be a backup for each other with duplicate capabilities.
Response: Any entity may exceed standards. Due to the infrequency of events that require backup functionality, the SDT weighed the risk of losing the system during a critical event and the increased expense to organizations to meet shorter times for availability of backup capabilities.			
FirstEnergy Corp.		x	We suggest allowing provisions if the transition time takes longer than 2 hours. Similar to the current requirement for transition time from EOP-008-0 Requirement R1.8, we suggest rewording R6 as follows: "Each Reliability Coordinator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours. Interim provisions must be included in the plan when extenuating circumstances cause the transition to take longer than two hours."
Hydro One Networks, Inc.		x	
Hydro Québec/TransÉnergie ISO New England NPCC Regional Standards Cmte.		x	R6 needs additional "sub-bullet" to address what happens if the two hour time limit on the RC implementation of the backup plan is exceeded, similar to R8.1. It is not the transition time that is in focus here but the system reliability issues which could come up during the transition period which needs to be looked at closely.
IESO			The existing requirement R1.8 stipulates that the responsible entity shall have interim provisions if the implementation of the back-up capability plan will take longer than one hour. This draft standard appears to be relaxing this requirement by changing it to two hours. What is the basis for this change? We can continue to support the 1 hour requirement. However, if a time frame is to be removed, we recommend that the requirement be written such that the responsible entity shall provide operational capability at all times to ensure continuous operation, monitoring and control of the BES. In this case, it will be up to the responsible entity to demonstrate how its operation and control will continue during the transition period, such as by arranging other

#3 – Commenter	Yes	No	Comment
			entities to take over operation and control during that period.
Madison Gas and Electric		x	A "less than two hour" window to fully implement the backup plan and get backup functionality up and running is and can be a great task. There should be a provision that if their backup plan cannot be obtained within the two hour time frame.
MA Dept. of Public Utilities NY State Dept. of Public Service			R1.8 of the existing standard - while not placing an absolute deadline - envisions that the backup for the primary control facility of the reliability coordinator will be operational within one hour. There is no explanation as to why one hour is no longer a credible target timeframe for backup facility operation and needs to be doubled to two hours. A more rationale approach is to institute a plan that is expected to have the backup control facility functional within one hour, but if there are unforeseen circumstances that prevent operation within one hour, then there will not be a penalty associated with the second hour. An example would be that if the circumstances that disabled the primary control facilities made access to the backup difficult (e.g. flood that took out both the control center and surrounding roads) and it physically took longer than expected to reach the backup center, then there would be no penalty until two hours elapsed. However, if the event was a computer glitch and there were no significant obstacles to reaching the backup facilities, the one hour limit would control. If this proposal is unworkable from a standards drafting perspective, the standard should only allow a one hour transition time consistent with the existing standard instead of a two hour limit as proposed. The longer the system is outside of a standard operating mode there is a higher risk of serious reliability problems, which should not be allowed at the reliability coordinator level.

Response: There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons:

- The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it.
- If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden.
- Realistic expectations for travel time in emergency conditions between the 2 centers.
- 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased

#3 – Commenter	Yes	No	Comment
reliability by reducing the risk of common events taking out both centers. • It is assumed that the TOP and BA are still functioning and can operate on their own for a 2 hour time period. • There is additional functionality required in this standard that wasn't there before. • Organizational inertia in responding to the disaster. • Cost benefit versus relative risk. • R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability. • It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
Midwest ISO		x	Why did the standards drafting team increase the transition time frame from the one hour requirement in the existing standards? The drafting team needs to provide strong justification for this. If all RCs are currently meeting the standard one hour transition time frame in the existing standards, it is hard to fathom any reason to increase it. Rather than specify a time frame for transition, we suggest alternative approach that is more justifiable. This approach would require the responsible entity to have minimal capability to meet the core set of applicable requirements during the transition. The drafting team will need to identify those core set of requirements.
Response: The SDT does not agree with the complete removal of the time-frame for having backup functionality available, as it would require a manned hot-standby site, which would likely be an unnecessary expense due to the infrequency of events that require such extreme advance preparations.			
Nebraska Public Power District		x	The 2-hour transition time is too restrictive - recommend a minimum of six hours.
Response: The SDT believes that all RCs will be able to meet the 2-hour transition, as they are currently required to adhere to a 1 hour transition period. There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons: • The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it. • If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden. • Realistic expectations for travel time in emergency conditions between the 2 centers. • 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers.			

#3 – Commenter	Yes	No	Comment
• It is assumed that the TOP and BA are still functioning and can operate on their own for a 2 hour time period. • There is additional functionality required in this standard that wasn't there before. • Organizational inertia in responding to the disaster. • Cost benefit versus relative risk. • R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability. • It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
PJM Interconnection		x	The current, approved version of EOP-008, R1.8, states "Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility." We believe this time-frame is appropriate and in the best interest of system reliability, and therefore should not be relaxed.
Sacramento Municipal Utility Dist.		x	In the role of the RC, a 2-hour period is insufficient for required reliability covereage, and should be 1-hour.
SPP ORWG		x	Since Reliability Coordinators are currently required to adhere to a transition period of 1 hour, why shouldn't we maintain the 1-hour transition period requirement?
Response: The SDT extended the transition period to 2 hours to allow for the additional requirements that the new standard may have placed on the RCs. Nothing will prevent the RCs that have the ability to meet a shorter transition from doing so. There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons: • The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it. • If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden. • Realistic expectations for travel time in emergency conditions between the 2 centers. • 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers. • It is assumed that the TOP and BA are still functioning and can operate on their own for a 2 hour time period. • There is additional functionality required in this standard that wasn't there before. • Organizational inertia in responding to the disaster. • Cost benefit versus relative risk. • R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability.			

#3 – Commenter	Yes	No	Comment
• It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
Dominion Resources Dominion Virginia Power Entergy SERC OC Standards Review Group Southern Company Services, Inc. Southeastern RC	x	x	The term 'transition period' is ill-defined by the parenthetical expression that follows it. This leaves us unable to render an opinion. The parenthetical expression included in R6 should be broken out, more precisely defined, and placed in the standard as a measure for R6.
Response: The SDT has re-written Requirement R6 as the new Requirement R1.5 with all entities having the same transition time and has removed the parenthesis to make it clear as to what was meant by transition period. R1.5 A transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running that is less than two hours. R6. ~~Each Reliability Coordinator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours.~~			
Duke Energy Corp.	x	x	2 hours may be reasonable, however R6 is an ambiguous requirement. It is unclear exactly what the 2-hour transition period is referring to. It may not always be possible to establish an exactly precise point in time when primary control center functionality was lost. Likewise, it may not always be possible to define an exact point in time when backup functionality is "up and running". Furthermore, it is unclear whether this is just a requirement to have an appropriate 2-hour plan, or whether it is a requirement to always meet the 2-hour time limit, whether for tests or actual activation.
Response: Requirement R6 has been deleted and the transition issue is now handled in Requirement R1.5 R1.5 A transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running that is less than two hours. R6. ~~Each Reliability Coordinator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours.~~			
Entergy – System Planning	x	x	It is not apparent as to the basis for this number. Is it arbitrary or based on some technical concern? State as such. A statistical risk analysis would be ideal to determine this allowable time, if a valid model exists. If an arbitrary value is used, then an industry survey or something similar (experts/EPRI) may be appropriate.
Response: The SDT increased the transition time frame to allow RCs to meet any requirements that may have grown with the current draft of			

#3 – Commenter	Yes	No	Comment
the standard. The SDT used the EPRI document "Power System Backup Control Center Requirements, EPRI TR-103605, Project 2473-68, April 1994" and searched for other research. The EPRI document did not include timeframes for transition, and the SDT was unable to find other sources that discussed timeframes. Therefore, the SDT used the rationale listed in our response to ATC on this question. Please provide the source and title of any other research that you would like the SDT to consider in future drafts.			
ISO/RTO Council	x	x	The regulatory approved reliability standard currently requires that a responsible entity have interim provisions if the implementation of the back-up capability plan will take longer than one hour. This draft standard appears to be reducing the stringency of this requirement by changing it to two hours. What is the justification for this? Are there responsible entities experiencing difficulties meeting the requirement? If all responsible entities are currently compliant with the requirement, why increase the time frame? In fact, we recommend that time frame should not be considered. The entity should be responsible for meeting a core set of requirements at all times.
Response: The SDT increased the transition to the time frame to allow RCs to meet any requirements that may have grown with the current draft of the standard. The SDT does not agree with the complete removal of the time-frame for having backup functionality available, as it would require a manned hot-standby site, which would likely be an unnecessary expense due to the infrequency of events that require such extreme advance preparations. There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons: • The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it. • If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden. • Realistic expectations for travel time in emergency conditions between the 2 centers. • 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers. • It is assumed that the TOP and BA are still functioning and can operate on their own for a 2 hour time period. • There is additional functionality required in this standard that wasn't there before. • Organizational inertia in responding to the disaster. • Cost benefit versus relative risk. • R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability. • It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
Midwest Reliability	x	x	Not sure, where did the 2-hour transition time frame come from? Is it

<table>
<tr><th>#3 – Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>Organization</td><td></td><td></td><td>reasonable to assume that 2 hours may not be possible? For example, what if a snow/ice storm of the century hits the control area in question? The ice storm renders the primary control center inoperable. Mobility to the backup control center is arrested due to massive snow fall. Is a Reliability Coordinator still reasonably expected to have the backup control center operational within 2 hours after the loss of the primary control center? The weather I describe is probable and it's planned for in designing facilities shouldn't we at least consider this situation as a possibility? To account for this possibility perhaps this time frame and the other time frames listed in this standard should be modified to allow the Compliance Monitor the option to arrest this requirement during natural destroyers or not prescribe a specific time period but say to operators you must make every foreseeable effort to transition as soon as possible.</td></tr>
<tr><td colspan="4">Response: The SDT discussed the possibilities that might arise during actual events to prevent time-frames from being met. Rather than attempt to list all of the possibilities in the standard, the SDT determined that a violation of the time-frame would then use the appeal process and allow the RRO to determine if the violation was justified.
There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons:
The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it.
If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden.
Realistic expectations for travel time in emergency conditions between the 2 centers.
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R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability.
It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.</td></tr>
<tr><td>Allegheny Power</td><td>x</td><td></td><td>See comment to question #1.</td></tr>
<tr><td>Avista Corporation</td><td>x</td><td></td><td></td></tr>
</table>

#3 – Commenter	Yes	No	Comment
Baltimore Gas and Electric	x		
Bonneville Power Admin.	x		
Comision Federal de Electricidad	x		Because Reliability Coordinators have to be as soon as possibly ready to coordinate the different Control Areas.
DTE Energy	x		
Gainesville Regional Utilities	x		
Manitoba Hydro Energy Board	x		
Northeast Utilities	x		
Oncor Electric Delivery Company	x		
PacifiCorp	x		
Pacific Gas and Electric Company	x		
PS Commission of South Carolina	x		
Santee Cooper	x		The key term is "backup functionality". We believe it's quite reasonable and an appropriate time period to have the backup plan implemented and backup functionality in operation.
Sierra Pacific Power Company	x		
Sierra Pacific Resources Transm.	x		Most entities target 30-60 minutes as the time frame to start up their backup centers. Allowing two hours is appropriate.
Tampa Electric Company	x		
WECC Operating Practices Subc.	x		
Xcel Energy	x		
Response: Thank you for your response. Note that in response to comments from other stakeholders, the SDT has revised the wording of this requirement. Please see the Summary Consideration for this question.			

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

Summary Consideration: Due to comments made by the industry to this question, the timeframes have been changed so that all entities now have the same 2 hour timeframe. Changes were made to the following requirements due to comments raised:

R1.5: A transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours.
R1.6: An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to get backup functionality up and running. The Operating Process shall include:
R1.6.1. A list of all entities to notify when there is a change in operating locations.
R1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary/backup functionality.
~~**R6.** Each Reliability Coordinator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours.~~
~~**R7.** Each Balancing Authority and applicable Transmission Operator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than six hours.~~
~~**R8.** For each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations.~~
~~**R8.1.** For each applicable Transmission Operator, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the situational awareness and control of facilities with defined Interconnection Reliability Operating Limits (IROLs) beyond the two hour time period.~~
~~**R8.2.** For each Balancing Authority, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the calculation and control of its ACE beyond the two hour time period.~~

#4 – Commenter	Yes	No	Comment
Allegheny Power		x	The difference in the transition time frame for the RC compared to the TOP and BA would seem to indicate that the loss of the functions of the RC are deemed to be more critical to the reliability of the BES than the loss of the functions conducted by the TOP and BA. To the contrary, it is most likely that the RC functions are dependant on the data supplied from a TOP or BA. The loss of the TOP or BA primary facility could deprive the RC of critical information. A 2-hour transition time seems appropriate for all three entities.
American Transmission Company		x	Should be the same as requirement 6.
Hydro Québec/TransÉnergie		x	HQT believe that bullets 8.1 and 8.2 are not related to requirement 8, perhaps these should be relocated to requirement 7.

#4 – Commenter	Yes	No	Comment
			The SDT should clarify why the RC has a maximum delay of 2 hour with no leeway for longer time while the TOP and BA have a maximum delay of 6 hour with a process to have situational awareness if the delay is planned to be greater than 2 hour. HQT believe that the three entities should have the same time delay and leeway time. See our answer to Q3.
Manitoba Hydro Energy Board		x	The time frame is too long, a lot can happen in six hours including mother nature dropping a lightning storm on top of the entity, which can cause much greater problems to the entity than the limited control they have during a transition period. I would suggest a time period of two hours.
Northeast Utilities		x	2 hours maximum seems more appropriate.
Sacramento Municipal Utility Dist.		x	In the role of a BA or TOP, a 2 to 6-hour time frame is insufficient for required reliable operation of the BES, and should be no greater than 2-hours.
SPP ORWG		x	The transition plan should be a constant 2 hours for BAs and TOPS. This would then eliminate the need for R8.1 and R8.2.
Response: The SDT has changed requirement R.6 and moved it to R1.5 and deleted R.7, R.8, R.8.1, and R.8.2 such that TOP's and BA's must implement their backup functionality within 2 hours.			
Baltimore Gas and Electric		x	If greater than 2 hours, only if their plan includes processes that will ensure the situational awareness and control of facilities. We are unclear as to how this can be accomplished without someone physically being at the backup control center within the initial 2 hour period.
MA Dept. of Public Utilities			Regardless of the timeframe between a primary control center going down and activation of the backup facility, having a plan in place to seamlessly operate the system is paramount. As stated in question 3, one hour should be used for the reliability coordinator instead of two hours.
NY State Dept. of Public Service		x	Regardless of the timeframe between a primary control center going down and activation of the backup facility, having a plan in place to seamlessly operate the system is paramount. As stated in question 3, one hour should be used for the reliability coordinator instead of two hours.
Bonneville Power Admin.		x	For quiet periods of operation, 2-6 hours is adequate. However for challenging times (peak loads, storms, loss of major generation, operating near IROL or SOL limits) 2 hours is insufficient. In 2003, a company did not have situational awareness visibility for 30-60 minutes with very adverse consequences. NERC, the SDT and NERC entities should consider these adverse situations

#4 – Commenter	Yes	No	Comment
			occuring during loss of control center. Could recent disturbances this month be managed during the transition to their current backup control center?

Response: The SDT added language to requirement R.1.6 that requires all entities to have a plan that manages risk to the BES during the 2 hour transition period. There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons:

- The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it.
- If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden.
- Realistic expectations for travel time in emergency conditions between the 2 centers.
- 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers.
- There is additional functionality required in this standard that wasn't there before.
- Organizational inertia in responding to the disaster.
- Cost benefit versus relative risk.
- R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability.
- It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.

#4 – Commenter	Yes	No	Comment
Dominion Virginia Power Dominion Resources Entergy SERC OC Standards Review Group Southern Company Services, Inc Southeastern RC		x	DVP believes R8.1 and R8.2 are not appropriate subrequirements of Requirement 8 since they pertain to required functionality in the transition period while R8 pertains to a requirement for a notification list. We also believes that all functional entities subject to this standard in its current form should have a two hour transition period. As currently written, R8.1 and R8.2 are essentially unmeasureable.
ISO New England		x	Bullets 8.1 and 8.2 appear to be related to requirement 7, not 8.
Madison Gas and Electric	x		Since R8.1 and R8.2 break down R7, they should be renumbered as sub bullets to R7.
NPCC Regional Standards Cmte.		x	NPCC participating members believe that bullets 8.1 and 8.2 are not related to requirement 8, perhaps these should be relocated to requirement 7.

Response: Requirements R.8.1 and R.8.2 have been eliminated with the change to require TOP's and BA's to transition to their backup functionality with a two hour time period.

#4 – Commenter	Yes	No	Comment
Duke Energy Corp.		x	6 hours is far too long to get backup functionality up and running. TOP's and

<table>
<tr><th>#4 – Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>BA's should be on the same 2-hour clock as the Reliability Coordinator. TOPs and BAs have direct communications to field locations and personnel that are critical under normal and emergency conditions. Many RCs do not have this capability and depend on TOPs and BAs to provide this link to the capability on the ground.

See response to Comment #3 above. While we believe 2 hours may be reasonable, R7 like R6 is an ambiguous requirement. It is unclear exactly what the transition period is referring to. It may not always be possible to establish an exactly precise point in time when primary control center functionality was lost. Likewise, it may not always be possible to define an exact point in time when backup functionality is "up and running". Furthermore, it is unclear whether this is just a requirement to have an appropriate plan, or whether it is a requirement to always meet the time limit, whether for tests or actual activation.</td></tr>
<tr><td colspan="4">Response: The SDT has changed requirement R.6 and moved it to R1.5, and deleted R.7, R.8, R.8.1, and R.8.2 such that TOP's and BA's must implement their backup functionality within 2 hours.

The SDT believes that most of the backup functionality will be met by computer systems that should log events and times to a level that would allow a time-line to be created in hindsight. In the event of a catastrophic failure that destroys the computer systems, loss of connectivity to other systems could be used. Dashboard summaries of systems and alarms on the failure of systems should be included to allow operations personnel to determine the health of systems in real-time and detect failures that would require the use of backup functionality.</td></tr>
<tr><td>Entergy – System Planning</td><td>x</td><td>x</td><td>It is not apparent as to the basis for this number. Is it arbitrary or based on some technical concern? State as such. A statistical risk analysis would be ideal to determine this allowable time, if a valid model exists. If an arbitrary value is used, then an industry survey or something similar (experts/EPRI) may be appropriate.</td></tr>
<tr><td colspan="4">Response: The SDT is not aware of available risk models for backup control center restoration analysis. There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons:
• The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it.
• If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden.
• Realistic expectations for travel time in emergency conditions between the 2 centers.
• 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers.
• There is additional functionality required in this standard that wasn't there before.</td></tr>
</table>

#4 – Commenter	Yes	No	Comment
• Organizational inertia in responding to the disaster. • Cost benefit versus relative risk. • R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability. • It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
FirstEnergy Corp.		x	We do not agree with the "6-hour" time frame. Also, we suggest allowing provisions if the transition time takes longer than 2 hours. Similar to the current requirement for transition time from EOP-008-0 Requirement R1.8, we suggest rewording R7 and R8 as follows [rewording also includes GOP with centralized dispatched control center based on our comments from Question #2]: R7: "Each Balancing Authority, Transmission Operator, and Generator Operator with a centrally dispatched control center shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is no more than one hour. Interim provisions must be included if it is less than two hours. Interim provisions must be included in the plan when extenuating circumstances cause the transition to take longer than two hours." For R8, we suggest rewording as follows: "For each Reliability Coordinator, Balancing Authority, Transmission Operator, and Generator Operator with a centrally dispatched control center, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations. R8.1 & R8.2 - We believe that these requirements are not necessary. Requirement R1.5 already includes requirements for the transition period while backup functionality is obtained. We suggest removing these requirements.
Response: The SDT has changed requirement R.6 and moved it to R1.5 and deleted R.7, R.8, R.8.1, and R.8.2 such that TOP's and BA's must implement their backup functionality within 2 hours. See question #2 for comments on GOP's. The SDT added language to requirement R.1.6 that requires all entities to have a plan that manages risk to the BES during the 2 hour transition period.			
Hydro One Networks, Inc.	x	x	The timeframe for the TOP should depend on whether its RC has the capability to be in "operational control" within 2 hours. There is no point in the RC be up and running within the 2 hours frame if they cannot control the system (e.g. switch, breakers). If the TOP is the only entity with "operational control" of

#4 – Commenter	Yes	No	Comment
			Critial Assets or IROLs, then they must also be required to be up and running in the same timeframe as the RC. Requirement R8.1. touches on this concept however, we suggest the words are changed to provide for more clarity.
IESO		x	We do not understand the rationale behind the difference in the 2-hour time frame for the RC and the 6-hour time frame for the BA/TOP. Mosts RCs rely on the BAs and TOPs to implement actions to ensure reliable operation of its RC area. They will be helpless to have directives implemented if the TOP or BA does not have a functioning control center or alternate plan to perform actions such as switching in the field or dispatch at the plant to meet its 2 hour. Thus, a six hour outage of a BA could in effect be equivalent to a six-hour outage of the RC. These times should match what is ultimately decided for the RC. Additionally, we urge the SDT to consider our suggestion made in Q3 that: ".. the requirement be written such that the responsible entity shall provide operational capability at all times to ensure continuous operation, monitoring and control of the BES.
ISO/RTO Council		x	Most RCs only have functional control of the transmission system. They will be helpless to have directives implemented if the TOP or BA does not have a functioning control center or alternate plan to perform actions such as switching in the field or dispatch at the plant. Thus, a six hour outage of a BA could in effect be equivalent to a six-hour outage of the RC. These times should match what is ultimately decided for the RC. In fact, we recommend an alternative approach to a time limit in question 3. We repeat that here and suggest it for application to the TOP and BA as well. In fact, we recommend that time frame should not be considered. The entity should be responsible for meeting a core set of requirements at all times.
Midwest ISO		x	Most RCs only have functional control of the transmission system. They will be helpless to have directives implemented if the TOP or BA does not have a functioning control center or alternate plan to perform actions such as switching in the field or dispatch at the plant. Thus, a six hour outage of a BA could in effect be equivalent to a six-hour outage of the RC. These times should match what is ultimately decided for the RC unless our alternative approach in our response to question three is adopted.

#4 – Commenter	Yes	No	Comment
			Our alternative approach presented in our comments in question three should apply here as well. It is included below. Rather than specify a time frame for transition, we suggest alternative approach that is more justifiable. This approach would require the responsible entity to have minimal capability to meet the core set of applicable requirements during the transition. The drafting team will need to identify those core set of requirements.
PJM Interconnection		x	RC's typically have a limited ability to control generation or transmission facilities. Without the BA and TOP control facilities, the RC will not be able to effectively perform its' functions. Therefore, the BA and TOP entities should be required to meet the same one hour time limit that applies to RCs.
Response: The SDT has changed requirement R.6 and moved it to R1.5 and deleted R.7, R.8, R.8.1, and R.8.2 such that TOP's and BA's must implement their backup functionality within 2 hours. The SDT added language to requirement R.1.6 that requires all entities to have a plan that manages risk to the BES during the 2 hour transition period. Each entity will need to develop its individual plan to meet these requirements. The SDT did not feel that it was possible to provide greater detail for this plan given the many and varied circumstances of individual RC's, TOP's and BA's.			
Nebraska Public Power District		x	This standard addresses an event that probably will never happen for the vast majority of TO's and BA's. Shorter time frames require more elaborate and expensive systems (i.e. hot back-up versus cold back-up). The additional complexity isn't justified by the probability of having an event. Instead of two hours, the time to transition functions to the backup should be six hours. The backup should be fully functional within 24 hours after the event. An actual event, noted to be extremely rare to occur, will probably result in the loss of human life and infrastructure. The initial discovery and realization to implement the backup will be delayed by emergency response and the real-world crisis. Shorter response times could require 7 X 24 staffing at the Backup Facility. I'm not aware of a significant number of actual events that had demonstrated this need.
Response: The SDT attempted to weigh all of these issues in determining applicability and time frames for implementing backup capabilities. It is not the intent of the SDT to require all entities to provide "hot" backup capabilities.			
Santee Cooper	x		To have the backup plan implemented and backup functionality in operation in a two to three hour period is quite reasonable in our opinion. We do believe that it should be at least two hours but perhaps no more than three hours. Smaller

#4 – Commenter	Yes	No	Comment
			entities that need a larger physical separation between control centers will need at least two hours. In most cases, three hours should be the limit.
Sierra Pacific Power Company		x	By allowing a six hour transition period,the standard basically is saying that a BA's ACE is unimportant for that time period. The old requirement of 1/2 hour should be maintained.
Response: The SDT has changed requirement R.6 and moved it to R1.5 and deleted R.7, R.8, R.8.1, and R.8.2 such that TOP's and BA's must implement their backup functionality within 2 hours. The SDT added language to requirement R.1.6 that requires all entities to have a plan that manages risk to the BES during the 2 hour transition period.			
Midwest Reliability Organization	x	x	The MRO would like to question why in this era of "hot" standby systems would it take an RC 6 hours to get their backup site operating? The MRO would like the SDT to share the methodology they used in determining these time periods.
Response: Requirement R6 (now R1.5) requires backup functionality up and running in less than 2 hours. There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons: • The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it. • If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden. • Realistic expectations for travel time in emergency conditions between the 2 centers. • 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers. • There is additional functionality required in this standard that wasn't there before. • Organizational inertia in responding to the disaster. • Cost benefit versus relative risk. • R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability. • It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
Avista Corporation	x		
Chelan County PUD	x		6 hours is a long time, however I know that some utilities have to travel long distances to their backup control center. It is difficult to imagine a scenario where we wouldn't be able to be up and running in less than 1 hour.
Comision Federal de Electricidad	x		
DTE Energy	x		

#4 – Commenter	Yes	No	Comment
Gainesville Regional Utilities	x		
Oncor Electric Delivery Company	x		
PacifiCorp	x		
Pacific Gas and Electric Company	x		
PS Commission of South Carolina	x		
Sierra Pacific Resources Transm.	x		I don't disagree with 6 hours for BA's and TOP's as a Requirement, although, I believe the industry entities can do much better tha
Tampa Electric Company	x		
WECC Operating Practices Subc.	x		
Xcel Energy	x		
Response: Thank you for your response. Please see the summary consideration – the drafting team modified the standard so that the backup plan for all responsible entities requires backup functionality up and running in less than 2 hours.			

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

Summary Consideration: There was a wide range of comments regarding the 2 hours. Some suggested a longer period others, suggested it be deleted altogether. The intent of the 2 hours was to test the basic functionality such as SCADA, alarm monitoring, voice & data communications, AGC, state estimator and Contingency evaluation, evacuation procedures & protocols, situational awareness tools, etc. Therefore the SDT feels that 2 hours is sufficient to test these basic functions. The 2 hours also allows enough time to operate through schedule changes over top of the hour. Testing all functions may not be practical since some functions are dependent upon system conditions (i.e., voltage reduction or load shedding would only be tested if needed). In addition entities may have different tools and different testing needs.

The other significant issue was in regards to integrating operator training into the test. The SDT decided operator training issues are best left with the PER standards, therefore these comments were not included though it does not preclude an entity from integrating operating training into the test.

Comments also identified that the requirement was not clear as to whether the 2 hours is continuous. The standard was revised to make clear the requirement is 2 continuous hours annually.

It should be noted that the intent of the standard is to verify the functionality of the Operating Plan through actual implementation, or through test operations, of the backup functionality for two continuous hours. It is not required that each operator be tested on these plans for two hours annually.

Others comments stated that Requirement R12 was more appropriate as a measure for Requirement R6. However, these are 2 distinct requirements, Requirement R6 (now R1.5) being the time to transition to the BCC and Requirement R12 (now R8) the test duration. Therefore these comments do not require a change to the standard.

Due to industry comments, Requirement R12 (R8 in the revised standard) was changed as follows:

~~R12.~~ R8. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall conduct an annual test of its Operating Plan that includes: ~~for backup functionality through actual implementation or test operations for a minimum of two continuous hours annually.~~ *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R8.1 A demonstration of the transition time between the primary control center and the initiation of backup functionality.

R8.2 Actual implementation or test operations of the backup functionality for a minimum of two continuous hours.

R8.3 Test results shall be documented and lessons learned noted and incorporated in subsequent revisions of the Operating Plan for backup functionality.

#5 – Commenter	Yes	No	Comment
Allegheny Power		X	A 2 hour test would most likely not be long enough to test all the functions that

#5 – Commenter	Yes	No	Comment
			occur in a routine day. A minimum time requirement makes less sense than requiring that all functions required to be conducted during a normal day be tested.
Response: This is a test of the plan – not training. Training is left to PER. 2 hours allows one to go across an hour boundary and therefore to see schedules and ramps in action. If it takes up to 2 hours to transition to the backup site, then a 2 hour test will basically occupy a shift. This should be sufficient to show that the plan is 'real'. It represents a significant step up from the original standard. You can always do more.			
Baltimore Gas and Electric		x	The requirement should state that all operating personnel should operate real-time at the backup facility for a minimum of 1 shift per year in order to stay proficient with the transistion plan and the operations at the backup facility. This also provides more thourogh testing of the equipment at the backup facility when the center is utilized for real-time operations.
Sacramento Municipal Utility Dist.		x	To ensure familiarity with an entity's BCC, a minimum of two weeks (14 days) should be required to ensure all operator crews have the necessary experience.
Response: The SDT considered this but after deliberation decided this was best covered by the PER Standards regarding training.			
Bonneville Power Admin.		x	One specific change - "power sources" such as engine generators and UPS should be tested more often, weekly or monthly. In disturbances, control center EGs and UPS are often problematic. Also, if the backup software systems must be up to date as mentioned in R1.3 how does a BA or TO know without testing? Change the language to "adequately test all functions of the backup control center that are needed to replace the primary control center operation." For example: - test AGC for two hours annually, or when changes that impact operation - test voltage control for two hours. - test power sources EG/UPS monthly NERC CIP standards have requirements more frequent than annually that apply to backup control centers.
Response: Frequency of backup generators and UPS testing is developed considering many factors, most significantly vendor recommendations. Therefore, it would be imprudent for the standard to specify a testing frequency for backup power supplies. The intent of the 2 hours was to test the basic functionality such as SCADA, alarm monitoring, voice & data communications, AGC, state estimator and contingency evaluation, evacuation procedures and protocols, situational awareness tools, etc. The 2 hours also allows enough time to operate through schedule changes over top of the hour. Testing all functions may not be practical since some functions are dependent upon system conditions (i.e., voltage reduction or load shedding would only be tested if needed). In addition entities may have different tools and different testing needs.			

#5 – Commenter	Yes	No	Comment
Dominion Virginia Power (1) Dominion Virginia Power (2) Entergy SERC OC Standards Review Group		x	DVP believes that R12 is more appropriate as a measure for R6, and the number of required hours to test the plan is immaterial to reliability.
Southern Company Services, Inc.	x	x	Southern Company: Southern believes that R12 is more appropriate as a measure for R6 and the number of required hours to test the plan is immaterial to reliability. There seems to be an emphasis on "two hours" here. The real empahsis should be on each applicable entity performing an adequate test of their backup facility. Southeastern RC comment: Agrees with this.
Response: R6 & 7 (now R1.5) define a transition times, R12 (now R8) defines testing durations. The intent of the 2 hours was to test the basic functionality such as SCADA, alarm monitoring, voice & data communications, AGC, state estimator and contingency evaluation, evacuation procedures and protocols, situational awareness tools, etc. The 2 hours also allows enough time to operate through schedule changes over top of the hour. Testing all functions may not be practical since some functions are dependent upon system conditions (i.e., voltage reduction or load shedding would only be tested if needed). In addition entities may have different tools and different testing needs.			
Duke Energy Corp.		x	A single test of 2 hours duration annually is of very limited value for system operators and the backup functionality. This significantly limits the number of system operators who experience backup control, but more importantly minimizes the capability testing of the backup control functionality. This is a very low hurdle. This requirement is also silent on backup control functionality training. Specific training should be included in the training standards.
Entergy – System Planning	x	x	It is not apparent as to the basis for this number. Is it arbitrary or based on some technical concern? State as such. Otherwise, the testing should be of adequate length to test the back up functions, whether it be 30 minutes or 12 hours would be dependent upon the entity's desires.
FirstEnergy Corp.		x	We agree with testing is very important. We also think that it is important enough that it should be performed more frequently and longer each time. We suggest a change from "two hours annually" to "four continuous hours semi-annually".
IESO ISO/RTO Council		x	There should be a mininum amount of testing required. However, we don't see a justification for two hours. We ask the SDT to provide a justification for this important time frame. In the absence of a technical justification, we recommend a full testing of an entity's backup plan be completed regardless of

#5 – Commenter	Yes	No	Comment
			the time required.
Madison Gas and Electric		x	There should be adequate testing of the backup facility. A two hour annual test could consist of four, 30 minute periods. R12 should be written that "... implementation or test operations to ensure the RC, TOP, BA's minimum requirements are met per R1". This would ensure that the Operating Plan was implemented and all sub bullets of R1 are tested or simulated. As a BA, we would want to see an entire hour (hour ending X to hour ending Y) of information. This would allow us to ensure that the Operating Plan of R1 is satisified.
Midwest ISO		x	There should be a mininum amount of testing required. However, we don't see a justification for two hours. Why not one or three? The SDT should establish a justification for this important time frame. It should not be arbitrary or based on judgment.
PJM Interconnection		x	The two hour requirement appears to be arbitrary and should not be included in the standard. The standard should state something to the effect that “Each Reliability Coordinator, Balancing Authority and Transmission Operator shall test its Operating Plan for backup functionality through actual implementation or test operations on a semi-annual basis.”
Response: The intent of the 2 hours was to test the basic functionality such as SCADA, alarm monitoring, voice & data communications, AGC, state estimator and contingency evaluation, evacuation procedures and protocols, situational awareness tools, etc. The 2 hours also allows enough time to operate through schedule changes over top of the hour. Testing all functions may not be practical since some functions are dependent upon system conditions (i.e., voltage reduction or load shedding would only be tested if needed). In addition entities may have different tools and different testing needs. The SDT considered adding training requirements but decided this was best covered by the PER Standards regarding training.			
Gainesville Regional Utilities		x	I do believe that the BU facility, (If one has been established) should be tested annually by the operations personnel once a year. Not necessarily 2 hours a year.
Hydro One Networks, Inc.	x	x	Yes: 2 hours annually is appropriate. However please clarify if this requirement should read, "minimum of two CONTINUOUS hours, annually." Also, is there consideration in the variance of testing the Operating Plan with respect to weather conditions (e.g. summer conditions vs. winter conditions)? In some locations, weather conditions may have a significant impact on staff transportation time.
Xcel Energy	x		The provision should be revised to clarify whether the two-hour testing requirement is cumulative over the course of a year or whether the two-hour

#5 – Commenter	Yes	No	Comment
			test is to be achieved over the course of two consecutive hours.
Response: R12 (now R8) was changed to clarify the intent of the SDT. It now reads: ~~R12.~~ R8. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall conduct an annual test of its Operating Plan that includes: ~~for backup functionality through actual implementation or test operations for a minimum of two continuous hours annually.~~ *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* R8.1 A demonstration of the transition time between the primary control center and the initiation of backup functionality. R8.2 Actual implementation or test operations of the backup functionality for a minimum of two continuous hours. R8.3 Test results shall be documented and lessons learned noted and incorporated in subsequent revisions of the Operating Plan for backup functionality.			
Manitoba Hydro Energy Board		x	I think the time frame should be left up to the entity, they just have to ensure the backup is tested thoroughly.
Santee Cooper		x	We believe that should be left to the individual company and their corporate procedures. If you require it, it could unnecessarily introduce reliability problems to the real-time system.
Response: The intent of the 2 hours was to test the basic functionality such as SCADA, alarm monitoring, voice & data communications, AGC, state estimator and contingency evaluation, evacuation procedures and protocols, situational awareness tools, etc. The 2 hours also allows enough time to operate through schedule changes over top of the hour. Testing all functions may not be practical since some functions are dependent upon system conditions (i.e. voltage reduction or load shedding would only be tested if needed). In addition entities may have different tools and different testing needs. The test can always be rescheduled or aborted should system conditions, weather, etc., present an unnecessary risk while testing the BCC.			
Midwest Reliability Organization	x	x	That depends on the conditions during the test. Operators may not be aware of specific issues with the back up control center if they only operate that location for two hour annually, plus, issues may emerge outside the 2 hour testing operational period;It's difficult to say what those issues may be at this time.
Response: The test can always be rescheduled or aborted should system conditions, weather, etc., present an unnecessary risk while testing the BCC. In addition it does not preclude taking precautions such as keeping the Primary Control Center staffed during the test.			
SPP ORWG		x	We would propose two hours quarterly.
Response: The objective is to ensure functionality. R1.3 requires a process to keep the BCC current with the Primary Control Center. Testing is meant to verify the functionality. Therefore it is not necessary to test more frequently.			
Pacific Gas and Electric Company	x	x	It is also unclear as to who will be testing it? Are the Operating Plans for the

#5 – Commenter	Yes	No	Comment
			functionality to be tested for the two hours annually, ment for each operator or is it only for that control center, once per year?
Response: The intent was a test whereby real time operations is being conducted at the BCC and therefore this would be done by operators.			
MA Dept. of Public Utilities			No comment.
NY State Dept. of Public Service			No comment.
American Transmission Company	x		The two hour testing is appropriate.
Chelan County PUD	x		
Comision Federal de Electricidad	x		If the assumption applies to the implementation or testing operations of the backup center and not each individual.
DTE Energy	x		
Hydro Québec/TransÉnergie	x		It is a minimum.
ISO New England	x		It is a minimum.
Nebraska Public Power District	x		
Northeast Utilities	x		Yes, as a minimum.
NPCC Regional Standards Cmte.	x		It is a minimumn
Oncor Electric Delivery Company	x		
PacifiCorp	x		
PS Commission of South Carolina	x		
Sierra Pacific Power Company	x		
Sierra Pacific Resources Transm.	x		This is a good idea. Having to operate through 1 or more hourly ramp periods is a reasonable test of functionality.
Tampa Electric Company	x		
WECC Operating Practices Subc.	x		If the assumption applies to the implementation or testing operations of the backup center and not each individual.

#5 – Commenter	Yes	No	Comment
Response: Thank you for your response. The testing relates to functionality – not to individuals. Please see the summary consideration – the drafting team modified the requirement to improve its clarity.			

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

Summary Consideration: The drafting team received several responses to this question. They were very nearly evenly divided between those that agreed with the requirement and those that disagreed from the point of view that six months is too long to allow an entity to develop a plan for re-establishing backup capability. After much discussion, the SDT has decided to leave Requirement R13 as currently written, allowing 6 months for developing a plan to re-establish backup capability after a major event causes the primary or backup functionality to be degraded for the reasons detailed in the responses. Changes were made to Requirements R4 and R5 in an attempt to clarify when these requirements are in effect:

R4: Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator.

R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively.

#6 – Commenter	Yes	No	Comment
Allegheny Power		x	The RC, TOP, or BA that losses it's primary or back-up control center should notify it's Regional Entity and neighboring entities within 24 hours. Within that 24 hour period, that entity should provide a plan that would outline how the loss of the remaining facility would be handled. There should always be a plan for the next contingency. A plan to re-establish a lost facility is less important that providing a plan to handle the loss of the remaining facility.
Response: The SDT agress that an entity that has lost its primary control center must contact its Regional Entity and re-establish communications with its RC and neighbors as soon as possible. The primary focus of an entity in this situation is ensuring that they are able to maintain visibility and control of its system, and that it has staff, equipment and logistics to ensure that its operation is sustainable. The SDT is concerned that it may not be evident within the first 24 hours whether the total loss of the primary or backup capability will last for more than 6 months. The SDT's intent is not that the lost facility or functionality be replaced within a specific timeframe, but that backup capability be restored to ensure that reliable operation of the BES is maintained if the remaining control center or functionality is lost. The SDT believes 6 months is a reasonable time period for the development of a plan because it allows for the following: • Need to recover from the actual incident. • Continuity of operations could delay the planning process.			

#6 – Commenter	Yes	No	Comment
• Time is needed to evaluate the damage to the affected site. • Development and evaluation of alternatives. • Internal approval cycles.			
American Transmission Company		x	Six months is an excessive amount of time to have a plan for re-establishing backup capability. ATC belives that three months is a more appropriate amount of time. Why does the SDT believe that six months is needed in order to develop a plan for re-establisting backup capability? ATC would say that establishing backup capability may take more than six months but to develop a plan should not take six months.
Chelan County PUD		x	6 months to develop a plan? No timeframe to have lost control facilities operational? Why have a requirement? Perhaps developing a plan in 3 months or less and demonstrating progress according to schedule to restore lost control functionality - or something like that.
Gainesville Regional Utilities		x	I believe this needs to be removed. because in the case of a primary facility being lost, everyone in the regiona including NERC and FERC will know the primary facility is lost. Remove requirement. Within 6 months a back up plan has been utilized during the time period.
Northeast Utilities		x	6 months seems excessive. It seems within 2 months an entity should at least have a plan.
Response: The SDT included Requirement R13 because we wanted to allow some period of time for an entity to develop a reasonable plan to restore backup capability for their remaining control facility in the event of a loss of primary or backup control capability. The SDT believes 6 month is a reasonable time period for the development of a plan because it allows for the following: • Need to recover from the actual incident. • Continuity of operations could delay the planning process. • Time is needed to evaluate the damage to the affected site. • Development and evaluation of alternatives. • Internal approval cycles.			
Avista Corporation		x	Change to 12 calendar months for a plan. Need wording to indicate you are specifically exempt from EOP-008 for a time period (24-36 months) for rebuilding your control center.
Response: The SDT has added language to the Requirements R4 & R5 to clarify that the standard is not applicable after the loss of the primary facility and after the backup functionality is fully implemented, as that would impose an obligation for a tertiary site.			

#6 – Commenter	Yes	No	Comment
R4: Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator. R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively. Depending upon the size and operational scope of entity, the SDT feels that 24 months to reestablish backup capability might be excessive. The SDT believes 6 months is a reasonable time period for the development of a plan because it allows for the following: • Need to recover from the actual incident. • Continuity of operations could delay the planning process. • Time is needed to evaluate the damage to the affected site. • Development and evaluation of alternatives. • Internal approval cycles.			
Baltimore Gas and Electric		x	What does "have a plan in place for re-establishing backup capability" mean? Does this mean a) - that the requirement is to have a plan to establish backup capability or b) - is the requirement to re-establish backup functionality within 6 months? If a) is the intent, 6 months is too long to only develop a plan. A temporary backup solution should be required much sooner than 6 months. As written, R13 is not clear. Need to clarify R13 requirement. It is not clear that the RC, BA, and TO need to supply the backup plan 6 months PRIOR to the anticipated date that they expect the primary or backup control center to be inoperable. As stated, it could be supplied 6 months after the date that the functionality is lost.
Response: "Have a plan in place for re-establishing backup capability" means a) as referenced in the question. The SDT included Requirement R13 because we wanted to allow some period of time for an entity that has sustained the loss of its primary control facility, and such loss is expected to last more than six calendar months, to develop a reasonable plan to restore backup capability for its remaining control facility. It was not intended that the entity would have to have a replacement for its lost control center within 6 months. It was not intended that the entity would have to supply the backup plan 6 months prior to the loss of its primary backup center. The SDT believes 6 months is a reasonable time period for the development of a plan because it allows for the following: • Need to recover from the actual incident.			

#6 – Commenter	Yes	No	Comment
• Continuity of operations could delay the planning process. • Time is needed to evaluate the damage to the affected site. • Development and evaluation of alternatives. • Internal approval cycles.			
Dominion Virginia Power Dominion Resources Entergy SERC OC Standards Review Group		x	This requirement is construed as attempting to give an entity an automatic waiver from R1 through R12 of this standard, following a catastrophic loss of its primary or backup control center (BUCC) that is a force majeure event. As written, it does not accomplish that goal. For example, what about the scenario where a primary control center is uninhabitable for longer than 2 hours? Is that entity immediately non compliant for this standard for having no backup for its BUCC?
Hydro Québec/TransÉnergie	x	x	HQT suggest the drafting team to provide for a compliance exemption should the primary or back up control center be lost because of a catastrophic failure.
NPCC Regional Standards Cmte.	x	x	NPCC participating members suggest the drafting team provide for a compliance exemption should the primary or back up control center be lost because of a catastrophic failure.
Southern Company Services, Inc.		x	Southern Company: This requirement can be interpreted as attempting to give an applicable entity an automatic waiver from R1 through R12 following a catastrophic loss of its primary or backup control center (BUCC) under a force majeure event. As written, it does not accomplish that goal. For example, what about the scenario where a primary control center is uninhabitable for longer than 2 hours? Is that entity immediately non compliant for this standard for having no backup for its BUCC? Southeastern RC comment: The answer is no, because the moment the primary center is lost, the RC, BA or TOP are out of Compliance. Thus to meet compliance, an entity would be required to have one primary and two backup centers. A lot of detail is lost in this requirement. It should state upon the loss of the primary center the RC, BA, or TOP are exempt from six (6) until a plan can be developed for an additional backup facility. The plan should include a backup center.

Response: The SDT has added language to the Requirements R4 & R5 to clarify that the standard is not applicable after the loss of the primary facility and after the backup functionality is fully implemented, as that would impose an obligation for a tertiary site.

R4: Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance

#6 – Commenter	Yes	No	Comment
with all Reliability Standards applicable to the Reliability Coordinator. R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively. The SDT recognizes that in the event of a complete loss of a control center it may likely require an extensive amount of time to rebuild the control center. It is the intention of the SDT to require that in the unlikely event of a loss of primary or backup functionality that is anticipated to last for more than six months, the RC, TOP or BA provide plans within six months to show how it will re-establish backup capability.			
Entergy – System Planning		x	Recommend a shorter time time frame such as within 30 days, and updated every 30 days until back up capability is restored. 6 months is too long for an entity to not have a plan for continuing operations if its primary or back up facility are unavailable. The plan itself may take longer than 6 months to complete.
Response: The SDT included Requirement R13 because we wanted to allow some period of time for an entity to develop a reasonable plan to restore backup capability for its remaining control facility in the event of a loss of primary or backup capability. The SDT agrees that implementation of the plan may take longer than 6 months to complete, depending upon the scope and required functionality for that entity, and for that reason we have not chosen to address how long the entity has to implement the plan. It is our intention that this level of detail will be left up to the Regional Entity. The SDT believes 6 months is a reasonable time period for the development of a plan because it allows for the following: • Need to recover from the actual incident. • Continuity of operations could delay the planning process. • Time is needed to evaluate the damage to the affected site. • Development and evaluation of alternatives. • Internal approval cycles.			
Hydro One Networks, Inc.		x	6 months is too long. We recommend 3-4 months. As well, please re-word the requirement to provide clairification on whether the plan is needed after the fact (while operating from the back-up facility) or in the planning stages of the Operating Plan? We referring the use of the word "anticipate" in the requirement. The phrases "… anticipate total loss … will last for more than six months…" and "… within six months of the date when the funcationality is lost.." seem to be in conflict.
Response: The SDT included Requirement R13 because we wanted to allow some period of time for an entity to develop a reasonable plan to restore backup capability for its remaining control facility after a loss of primary or backup capability. The SDT intends the meaning of the requirement to be that for an entity that has lost its primary control capability, and expects that the loss will last in excess of six calendar months to			

#6 – Commenter	Yes	No	Comment
submit a plan to re-establish backup capability to its Regional Entity. This plan would need to be submitted within 6 calendar months. The SDT believes 6 months is a reasonable time period for the development of a plan because it allows for the following: • Need to recover from the actual incident. • Continuity of operations could delay the planning process. • Time is needed to evaluate the damage to the affected site. • Development and evaluation of alternatives. • Internal approval cycles.			
IESO		x	We do not see the need for this requirement. It implies that the responsible entity must establish a long-term or an N-2 contingency plan. Losing a primary control capability/facility for a period longer than several days is a rare event, if it has ever occurred before. The need for a long-term plan seems unnecessary. If the backup capability is lost, then the responsible entity would fail its primary requirement of providing the backup capability, unless it immediately re-establish such a capability by securing new facilities or arranging backup by another entity. The need to provide a plan (within 6 months) if the backup capability is lost also seems unnecessary. In essence, no time frame needs to be stipulated; just a requirement for the responsible entity to demonstrate the backup capability requirement can continue to be met if the loss of either the primary of backup capability/facility is assessed to be indefinite.
Response: It is not the intent of the SDT to require an N-2 contingency plan. To make this clearer, the SDT added language to the applicability section of the standard to indicate that the standard would not be applicable during the time period after the loss of the primary control center and after the backup functionality is fully implemented. That is, there is not a requirement for a tertiary backup facility. The SDT included Requirement R13 because we wanted to allow some period of time for an entity to develop a reasonable plan to restore backup capability for their remaining control facility after a loss of primary or backup capability. The SDT believes 6 months is a reasonable time period for the development of a plan because it allows for the following: • Need to recover from the actual incident. • Continuity of operations could delay the planning process. • Time is needed to evaluate the damage to the affected site. • Development and evaluation of alternatives. • Internal approval cycles.			
Madison Gas and Electric		x	We do not "anticipate" the loss of our primary or backup capability. If a RC, TOP ,

#6 – Commenter	Yes	No	Comment
			or BA was without their primary control center for any length of time it would have an impact on their revenue generation and would place a burden on "whoever" was assisting them. I would think that the Regional Entity would be involved and the RC, TOP or BA would be working to get their primary control center up and running as soon as possible. FERC Order 693 does not state a 6 month time frame. R13 could state that the Regional Entity will be notified whenever the primary control center is non-functional except when the backup control center is being tested or training is taking place. The RE will have a plan fullfilling R1 requirements if the primary and backup facilities are non operatible.
Response: The requirement is not specifying that a TOP, BA, or RC "anticipate" the loss of primary or backup capability with all factors known (i.e., type of loss, extent of damage, time to rebuild, etc.) ahead of time. The requirement is specifying that a BA, TOP, or RC that has experienced a loss of primary or backup capability and anticipates at that time that it will take longer than 6 months to restore the lost capability, will provide a plan how it will re-establish backup capability. The SDT included Requirement R13 because we wanted to allow some period of time for an entity to develop a reasonable plan to restore backup capability for their remaining control facility after a loss of primary or backup capability.			
PacifiCorp		x	If the site for the backup facility must be completely reconstructed, it may not be feasible for it to be re-established within 6 calendar months. 6 months to a year would be more appropriate, allowing room to relocate and re-establish, if necessary.
Midwest Reliability Organization	x	x	Appropriateness depends on what is needed to show the re-establishment of backup capability. What if an action is contingenct upon restriants that may take awhile to process like a building permit or limiting weather conditions restricting the re-establishment process(es)?
Response: Requirement R13 is not intended to require that the backup capability be restored within 6 months, but rather that the entity that has experienced a total loss of its primary or backup capability develop a plan within six months showing how it will re-establish backup capability. The implementation of the plan may well take longer than 6 months, depending upon the size and operational scope of the entity.			
PJM Interconnection		x	The structure of the requirement is confusing. We suggest that it be re-written as "If the Primary or backup functionality is lost then each RC, TOP and BA shall provide a plan to its Regional Entity within six calendar months showing how it will re-establish backup capability."
Response: The intent of Requirement R13 is to require a plan to be submitted, if the primary or backup functionality is lost AND if the restoration of the functionality is expected to take more than 6 months. The SDT believes that the current wording conveys that intent.			
Sacramento Municipal Utility Dist.		x	2 years would be more appropriate to re-establish either a PCC or BCC.
Response: Requirement R13 is not intended to require that the backup capability be restored within 6 months, but rather that the entity that has			

<table>
<tr><th>#6 – Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td colspan="4">experienced a total loss of its primary or backup capability develop a plan within six months showing how it will re-establish backup capability. The implementation of the plan may well take longer than 6 months, depending upon the size and operational scope of the entity.</td></tr>
<tr><td>Duke Energy Corp.</td><td>x</td><td>x</td><td>This requirement seems reasonable, but needs more clarity. If the view of this requirement is that backup capability must be re-established within 6 months of the loss of primary functionality, we question whether it can done, particularly in situations where the primary capability is totally destroyed. Furthermore, while an entity is in the backup facility, perhaps for 6 months or longer while the primary facility is being restored, there should be a clear exemption from having a "backup for the backup", since the need for such a facility would be a very low probability event. Similarly, if more than one entity plans to utilize the same backup facility they should not be found non-compliant when another entity is utilizing the facility. The SDT should provide more clarity and specificity around the exceptions from requirements in the standard for these types of situations.</td></tr>
<tr><td colspan="4">Response: Requirement R13 is not intended to require that the backup capability be restored within 6 months, but rather that the entity that has experienced a total loss of its primary or backup capability develop a plan within six months showing how it will re-establish backup capability. The implementation of the plan may well take longer than 6 months, depending upon the size and operational scope of the entity.

The SDT has attempted to address this by including language in Requirements R4 & R5 making it clear that the standard is not applicable after the loss of the primary control center and after the implementation of the backup functionality is complete. That is, there is not a requirement to have a tertiary facility or functionality.

R4: Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator.

R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively.</td></tr>
<tr><td>ISO New England
ISO/RTO Council
Manitoba Hydro Energy Board
Midwest ISO</td><td>x</td><td>x</td><td>This requirement is trying to anticipate every conceivable situation that could occur. Standards should not be written to anticipate all possible situations. In reality, this is a business continuity issue and does not belong in the standard. Most professionals with business continuity responsibilities believe that the risk of losing your main control center for such an extended period is extremely low. Most likely an entity will only have to implement their back-up capability plan for a short period of time and will be able to re-occupy their main control center.</td></tr>
</table>

#6 – Commenter	Yes	No	Comment
			Additionally, there are simply too many variables involved in establishing new backup capability for an extended period of time. The ERO and REs should work closely with the affected entity to develop a plan to restore backup capability to address this unlikely situation.
Response: The SDT does not agree that the requirement is trying to anticipate every conceivable situation. The SDT agrees that the loss of primary or backup capability is a low probability event. However, NERC and FERC believe that the potential impact to the Bulk Electric System due to such an event is great. Requirement R13 is intended to address the risk to the BES in the unlikely occurrence of the loss of primary or backup capability that is anticipated to last six months or more.			
MA Dept. of Public Utilities			No comment.
NY State Dept. of Public Service			No comment.
Bonneville Power Admin.	x		Having a plan in place within six months is reasonable if this includes getting budget approval for replacement. Having it functional within six months may prove difficult. EMS vendors have said they can complete a project in about 12-18 months. NERC should suggest or require that the backup be functional again in a specific time period such as 18-24 months after failure of the primary control center.
Comision Federal de Electricidad	x		6 months is reasonable and makes its clear of the requirement that has not been available in the past.
DTE Energy	x		
FirstEnergy Corp.	x		
Nebraska Public Power District	x		As long as it's a plan for re-establishing backup capability and not the actual backup capablity restored in six months, this requirement is achievable.
Oncor Electric Delivery Company	x		
Pacific Gas and Electric Company	x		
PS Commission of South Carolina	x		
Santee Cooper	x		We believe that 6 months is reasonable for a plan. We do not believe it is reasonable to expect full recovery in 6 months.
Sierra Pacific Power Company	x		
Sierra Pacific Resources	x		

#6 – Commenter	Yes	No	Comment
Transm.			
SPP ORWG	x		
Tampa Electric Company	x		
WECC Operating Practices Subc.	x		6 months is reasonable and makes its clear of the requirement that has not been available in the past.
Xcel Energy	x		
Response: Thank you for your response. The intent is to have the plan in place within 6 months – not to implement the plan within 6 months. Please see the Summary Consideration – Changes were made to Requirements R4 and R5 in an attempt to clarify when these requirements are in effect.			

7. If you are aware of any regional variances that would be required as a result of this standard, or 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 them here.

Summary Consideration: Due to comments raised to this question, the SDT changed applicability criteria to eliminate the references to Critical Assets and has changed the timeframes so that all applicable entities now have the same 2 hour requirement. In addition, changes were made to address the transition period requirements. Specific changes were:

4.1.2. Transmission Operator ~~with control of Facilities that are designated as Critical Assets or with defined Interconnection Reliability Operating Limits (IROLs)~~ operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Reliability Entity to be critical to the reliability of the Bulk Electric System (BES).
R1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to get backup functionality up and running. The Operating Process shall include:
R1.6.1. A list of all entities that will be notify when there is a change in operating locations.
R1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary/backup functionality.
R8. ~~For each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations.~~
~~**R8.1**. For each applicable Transmission Operator, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the situational awareness and control of facilities with defined Interconnection Reliability Operating Limits (IROLs) beyond the two hour time period.~~
~~**R8.2**. For each Balancing Authority, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the calculation and control of its ACE beyond the two hour time period.~~

#7 – Commenter	Yes	No	Comment
IESO		x	Provided that our suggestion in the second part of Q1 is adopted. Letting TOP to decide if this standard applies to them based on their own determination of their critical assets and/or IROLs seems to be a self-regulation process, which violates the legislation establishing a requirement for the ERO.
ISO/RTO Council Midwest ISO	x		Allowing a BA or TOP to in effect determine if the standard applies to them because they determine their critical assets and/or IROLs is equivalent to self-regulation which is clearly a violation of the legislation establishing a requirement for the ERO.
Response: The use of critical assets as a determination of applicability has been removed. TOP applicability is now determined by: Transmission Operator ~~with control of Facilities that are designated as Critical Assets or with defined Interconnection Reliability Operating Limits~~			

#7 – Commenter	Yes	No	Comment
~~(IROLs)~~ operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Reliability Entity to be critical to the reliability of the Bulk Electric System (BES).			
DTE Energy	x		Previously identified FERC Order 693.
Response: Without any details being specified, the SDT is unable to respond to these comments.			
Hydro Québec/TransÉnergie	x		
Madison Gas and Electric	x		R8.2 states that the Operating Procedure will ensure the calculation and control of ACE beyond the two hour time period. BAL-005-0, R6 states that if a BA is unable to calculate ACE for more than 30 minutes it shall notify its RC. Perhaps the wording of R8.2 should be the same as BAL-005-0, R6 so there is no confusion.
Response: Requirement R8.2 has been deleted and new wording has been added to R1.5.2 to address this situation: R1.5.2 now reads: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary/backup functionality.			
Allegheny Power		x	
American Transmission Company			No comment.
Avista Corporation		x	
Baltimore Gas and Electric		x	
Bonneville Power Admin.		x	I don't know of any regional variation. However, for some BAs & TOPs, operating Special Protection Schemes is a critical issue for reliablility of the Bulk Electric System that may require a robust control center and backup control center. Additional requirements may be needed for managing SPS during all adverse power system conditions including loss of control center.
Chelan County PUD		x	
Comision Federal de Electricidad		x	Not aware of any at this time.
Dominion Virginia Power		x	
Dominion Resources		x	
Duke Energy Corp.		x	
Entergy – System Planning		x	

#7 – Commenter	Yes	No	Comment
Entergy		x	
FirstEnergy Corp.		x	
Gainesville Regional Utilities		x	
Hydro One Networks, Inc.			No comment.
ISO New England		x	
Manitoba Hydro Energy Board			No comment.
MA Dept. of Public Utilities			No comment.
Midwest Reliability Organization		x	N/A
Nebraska Public Power District		x	
NY State Dept. of Public Service			No comment.
Northeast Utilities		x	
NPCC Regional Standards Cmte.		x	
Oncor Electric Delivery Company			No comment.
PacifiCorp		x	
Pacific Gas and Electric Company		x	
PJM Interconnection		x	
PS Commission of South Carolina		x	
Sacramento Municipal Utility Dist.		x	Not aware of any at this time.
Santee Cooper		x	
SERC OC Standards Review Group		x	
Sierra Pacific Power Company			No comment.

#7 – Commenter	Yes	No	Comment
Sierra Pacific Resources Transm.		x	Not aware of any.
Southern Company Services, Inc.		x	
SPP ORWG		x	
Tampa Electric Company		x	
WECC Operating Practices Subc.		x	Not aware of any at this time.
Xcel Energy		x	
Response: Thank you for your response.			

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

Summary Consideration: Numerous changes were made to the requirements as a result of the comments to this question. Specific changes included:

R1.1. The location and method of implementation for providing backup functionality for a prolonged period of time.
R1.2. An ~~high level~~ overview of the elements required to support the backup functionality.
R1.3. An Operating Process for keeping the backup functionality ~~current~~ consistent with the primary control center.
R1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality. ~~including at a minimum:~~
R1.4.1. ~~Criteria for evacuation of the primary control center including the decision authority for initiating the Operating Plan for backup functionality and the Operating Process for initiation of backup functionality.~~
~~**R1.4.2.** Criteria for returning operations support to the primary control center including the decision authority and the Operating Process for returning to the primary control center.~~
R1.7. Identification of the roles for ~~all involved~~ personnel involved during the initiation and implementation of the Operating Plan for backup functionality ~~and for the return to the primary control center~~.

R4**:** Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator.
R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively.
~~**R7**. Each Balancing Authority and applicable Transmission Operator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than six hours.~~
~~**R8.** For each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations.~~
~~**R8.1**. For each applicable Transmission Operator, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the situational awareness and control of facilities with defined Interconnection Reliability Operating Limits (IROLs) beyond the two hour time period.~~
~~**R8.2**. For each Balancing Authority, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the calculation and control of its ACE beyond the two hour time period.~~
~~**R9**.~~ **R6.** Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~.
~~**R9.1.**~~ **R6.1** The update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to the backup location, capabilities, or ~~communication protocols~~ contact information.

~~R10.~~ **R7.** Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards.
R11. ~~Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that is capable of operating for an indefinite period of time.~~

#8 – Commenter	Yes	No	Comment
American Transmission Company	x		The standard introduces three new capitalized terms that are not defined in the Standard: Operating Plan, Operating Process and Operating Procedure. ATC does not agree with the creation of the three new terms and believes that the terms should be replaced with a more general statement; i.e. "plan, process or procedure" as follows: R1: Each RC, BA and TOP shall have a plan, process or procedure describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable. This plan, process or procedure for backup functionality shall include the following: R1.3 The plan, process or procedure shall document how the entity will maintain backup functionality current with the primary control center. R1.4 The plan, process or procedure shall document how the decision for implementation is to be made:
Response: Operating Plan, Operating Process, and Operating Procedure are all defined terms in the currently approved NERC Glossary. Therefore, no changes were made by the SDT.			
Avista Corporation	x		R8 requires further clarification. R9 - Requirement 9 should be moved under Requirement 1. The relation between the annual review and approval and the 60-day update and approval is not clear. R9.1 clarify to indicate "changes that effect the operating plan." R10 remove - basically a restatement of R4. Additionally "...any aspect of the

#8 – Commenter	Yes	No	Comment
			operation." encompases aspects that would not be related to the reliability of the system but would ba an aspect of the operation (i.e. filling out time sheets). R11 - remove - This requirement seems to be in conflict with the purpose of R1 and R13. R13- Recommed that this be changed to 1 year. If this actually happened, there will be other issues to consider which may be very complex and trying to make this decision in 6 months may apply undue pressure on the decision. We recommend exemption from EOP-008 until the completion of a plan to reestablish backup capability.
Response: R8 has been deleted. A portion of the requirement has been rewritten and moved to R1.5.1. R1 deals with what the plan should include whereas R9 (now R6) deals with the timeframes for review: i) annually <u>no matter what</u> and ii) within 60 days for major changes. There is no relationship between the 1 year and 60 day reviews. R9.1 – To say 'changes that affect the operating plan' is too general. The SDT has been more specific in order to identify significant changes (i.e., back-up location, capabilities, or communications protocols). The SDT has changed the wording in R9.1 (now R6.1) from 'communication protocol' to 'contact information' and it now reads: The update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to the backup location, capabilities, or ~~communication protocols~~ contact information. R10 (now R7) deals with RC, BA, & TOPs while R4 is specific to the RC. The SDT has changed the wording in R10 to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards. R11 – This requirement has been moved to R1.1 and reads "for a prolonged period of time" rather than "an indefinite period of time." R1.1 now reads: "The location and method of implementation for providing backup functionality for a prolonged period of time." R13 – The requirement (now R9) is to <u>provide</u> a plan within the 6 month timeframe. There is always a dilemma when it comes to timeframes and the SDT determined that 6 months would be a reasonable timeframe to submit a plan. One must remember that the 6 months is not to have a backup center up and running but to submit the plan.			
Baltimore Gas and Electric	x		R1.6 identification of roles for ALL involved personnel may be too prescriptive. Thinking of all the scenarios for a loss of control center, certain individuals may be playing different roles. We think it should say, "all operations personnel" rather than "all involved" to limit the scope of pre-defined roles so that individuals such as support personnel can be used to the maximum effectiveness. As written, R3 is not clear. Need to clarify the R3 requirement. It is not clear how the standard applies to those other entities that perform the BES Operations.

#8 – Commenter	Yes	No	Comment
Response: R1.7: The plan calls for the identification of the personnel that will be involved with backup. The SDT has changed the wording of R1.7: Identification of the roles for ~~all involved~~ personnel involved during the initiation and implementation of the Operating Plan for backup functionality ~~and for the return to the primary control center~~. R3: The SDT feels it is necessary to point out that the registered TOP is responsible to ensure that operations required to maintain the reliability of the BES, including those they delegate, must be backed up. The SDT has changed the wording of R3 to: Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality ~~those operations~~ in its Operating Plan for backup functionality.			
Bonneville Power Admin.	x		This is a good improvement for EOP-008. if a BA or TOP has a "hot" back up site that is staffed 24/7, less prescribed testing or documentation is needed. R1.3 - add a timeline to keep current, weekly or monthly. Daily would be to difficult. R5 - "includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to BA & TO" . ALL Reliability Standards is too broad. An extreme example: Do we need monitoring of vegetation management at the backup control center? No. BAL standards for BAs - Yes. Prepare a list of standards/requirements we must meet from the B/U site. R10 language "backup capability that does not depend on the primary control center for any aspect of its operation" may force companies to buy a development system for the backup site. An EMS vendor may be able to provide development system on a temporary basis. Change "any aspect of its real time operation" R13 - Add a specific schedule for completion of backup control center functionality in addition to a plan. 2 years is reasonable. Will utilities still be liable for sanctions and penalities during loss of control center incidents and especially the 2-6 hour transition? Please have NERC comment. This may change the business case for backup control center.
Response: The fact that a TOP or BA has a hot backup does not preclude them from complying with this standard. R1.3: The SDT feels that it would be difficult to prescribe a time for updates because of the need to update various types of data that require			

#8 – Commenter	Yes	No	Comment
different backup times. The backup must have all the data necessary for operations to resume within the times specified in this standard. Therefore, the SDT does not feel the need to add a timeline to R1.3. However, the SDT has made a slight change to R1.3 for clarity: An Operating Process for keeping the backup functionality ~~current~~ consistent with the primary control center. R5: Although at first glance it might seem that Reliability Standards could be easily categorized as either directly affecting system reliability or of secondary importance, the SDT determined after much discussion that it was not practical. Items that at first appear not to directly affect reliability might in fact have a significant impact depending on the duration that that backup operation is in effect. As an example, the blackout of 2003 was caused by a combination of issues related to pure “real time operating requirements” as well as the vegetation management issue that has been suggested is secondary. Since we need to contemplate extended operation under a backup configuration, the SDT concluded that it was inappropriate to exempt any standard. R10 (now R7): The SDT has removed the ‘any aspect of its operation’ and changed the wording to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards. R13 (now R9): The SDT wanted to stay away from specific completion timeframes and rather specify reasonable timeframes (6 months) for the formulation of a plan with its regional entity. Will utilities still be liable? - The SDT is attempting to address this issue to the best of their ability within their scope with the revised EOP-008. Requirements R7 and R8 have been removed from the Standard and all RC’s, BA’s & TOPs will have the same 2 hour requirement to establish reliable operations. In addition, the drafting team modified the applicability of the standard to clarify that during the two hour transition period, entities are not required to be compliant with the requirements in the standard.			
Chelan County PUD	x		We suggest the following for R10: Replace "for any aspect of its operation" with "any functionality required to maintain compliance with all applicable reliability standards".
Response: R10 (now R7): The SDT has removed the ‘any aspect of its operation’ and changed the wording to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards.			
Dominion Virginia Power Dominion Resources Entergy SERC OC Standards Review Group	x		1) There are no measures for the above requirements - therefore it is difficult to evaluate the impacts of their applicability. For example, the definition of what starts the transition period and what ends the transition period to the backup control center should be included in the standard. 2) Regarding R11 - what is an "indefinite period of time" and what would be a reasonable measure? 3) Regarding R4 and R5 - Not all requirements are created equal - some real-time operating requirements are essential to be backed up. 4) A general comment is that this standard, taken as a whole, appears to include

#8 – Commenter	Yes	No	Comment
			"how" language. Requirements should be limited to "what" is required. Much of what is included in this standard appears to be "good utility practice" and not reliability requirements and should be stripped from the standard.
Response: 1) Measures have been developed for the second posting. The transition period is the time between loss of functionality and the restoration of functionality at the backup center. R7 has been deleted and the requirement is now the same for all applicable entities. 2) R11 has been moved to R1.1: The location and method of implementation for providing backup functionality for a prolonged period of time. 3) R4 and 5: Although at first glance it might seem that Reliability Standards could be easily categorized as either directly affecting system reliability or of secondary importance, the SDT determined after much discussion that it was not practical. Items that at first appear not to directly affect reliability might in fact have a significant impact depending on the duration that that backup operation is in effect. As an example the blackout of 2003 was caused by a combination of issues related to pure “real time operating requirements” as well as the vegetation management issue that has been suggested is secondary. Since we need to contemplate extended operation under a backup configuration, the SDT concluded that it was inappropriate to exempt any standard. 4) The SDT believes it has addressed the ‘what’ and has not drifted into ‘how’. How entities address the requirements hasn’t been mentioned.			
Southern Company Services, Inc.	x		Southern Company: There are no measures for the above requirements - therefore it is difficult to evaluate the impacts of their applicability. For example, the definition of what starts the transition period and what ends the transition period to the backup control center should be made more clear in the standard. Regarding R11 - what is an "indefinite period of time" and what would be a reasonable measure? Regarding R4 and R5 - Not all requirements are created equal - some real-time operating requirements are essential to be backed up. Southern Company EMS Services: We have concerns where an entity's current EMS system would not be compliant with the proposed standard, there should be adequate lead time for entities to make changes to their infrastructure to become compliant. Therefore, we would recommend an implementation plan to be a minimum of 2-3 years for this to occur. How does this standard address computer infrastructure which can be geographically separate from the control centers and backup facilities? If and when an event occurs, and one of the redundant sites is lost, what is the impact to compliance?
Response: Measures have been developed for the second posting. The transition period is the time between loss of functionality and the restoration of functionality at the backup center. R11 has been moved to R1.1: The location and method of implementation for providing backup functionality for a prolonged period of time. The Implementation Plan has been submitted with the second posting and provides a minimum of 2 years to become compliant from the time the standard is approved by applicable regulatory authorities.			

#8 – Commenter	Yes	No	Comment
This standard stresses functionality regardless of where equipment is located. Compliance is not within the scope of the SDT – it is an auditing function.			
DTE Energy	x		We would recommend that language for annual training for the operating personnel be included in the standard with a walkthrough and start up of the facility being the minimum. We feel the six calendar month language in R13 is to long of a time period.
Response: The SDT feels that the requirement for this standard is the operation of the back-up facility for 2 hours per year as per R12 (now R8). Training is the responsibility of the entity and is covered under another standard (Standard PER-002). R13 (now R9) – One must remember that 6 months is the time to submit a plan and not to have a backup center (or primary) fully functional. The SDT wanted to stay away from specific completion timeframes and rather specify reasonable timeframes (6 months) for the formulation of a plan with its regional entity.			
Duke Energy Corp.	x		The Purpose statement of this standard focuses on an event in which a control center becomes inoperable. Requirements then focus on providing "backup functionality" for a loss of primary control center functionality. The focus of the standard should be tightened up so that it is clear that entities are required to provide backup functionality that addresses loss of primary control center functionality. R10 requires that backup capability cannot depend on the primary control center for any aspect of its operation. This standard should more specific regarding how far “out” into the communications network infrastructure entities must assume the primary facility functionality reaches, for the purpose of establishing backup functionality. R11 states that the backup capability must be capable of operating for an indefinite period of time. It's unclear how compliance will be determined for this requirement.
Response: The purpose statement does identify loss of Control Center Functionality and the requirements focus on ‘backup functionality’. There is only one requirement that directly identifies the primary facility capability and that is R13 (now R9). R10 (now R7) – It is not up to the SDT to be that specific. The primary and backup facilities need to be independent. R11 – Compliance elements have been submitted with the second posting. Note that the statement, “must be capable of operating for an indefinite period of time” was removed and is not in the revised standard.			
Entergy – System Planning	x		Consider adding provisions for short term planned and unplanned outages on either the primary or back up control center. This would be similar to outage

#8 – Commenter	Yes	No	Comment
			"time clocks" in the nuclear world. This would allow entities to make repairs, upgrades on the primary and back up control centers without automatically being non-compliant when conducting such activities. An example might be that the primary or back up control center not be unavailable (definition needed?) for more than 7 cumulative days per quarter. Exceptions may be granted by the Regional Compliance Enforcement Authority.
Response: See the revised R4 and R5. R4: Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator. R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively.			
FirstEnergy Corp.	x		1. Operating Plan, Operating Process, Operating Procedure - Some entities may use a combination of these documents or simply specific procedures or "steps" to ensure reliable backup functionality. The specific use of a Plan, Procedure, or Process may put additional burden on an entity to maintain additional and unnecessary documentation. Also, the use of all these terms make the wording awkward and degrade the readability of the standard. Therefore we suggest that anywhere an Operating Plan, Process or Procedure is required in this standard, that it simply states either a "plan" (note: small caps] or "steps required" that an entity be required to adhere to. If the SDT is bound to the use of the capitalized NERC terms, then, for flexibility, we suggest that anywhere an Operating Plan is required, that entities be allowed to provide an Operating Process or Operating Procedure as an alternative. Also, we suggest that anywhere an Operating Process is required, that an entity be allowed to provide an Operating Procedure as an alternative. We suggest an across the standard change from: a. "Operating Plan" to "Operating Plan, Operating Process, or Operating Procedure". [As an example of a precedent to using all three terms, see standard IRO-014-1 Requirement 1]

#8 – Commenter	Yes	No	Comment
			b: "Operating Process" to "Operating Process or Operating Procedure" 2. R1.2 - Suggest removing the phrase "high level" which is subjective. Providing simply an "overview" of the elements is a sufficient description. 3. R1.4.1 - This requirement is very confusing as written. To the point of the use of the terms Operating Plan, Process, and Procedure from our comment #1 above, this requirement needs to be simplified. We suggest rewording to simply: "Criteria for evacuation of the primary control center including the decision authority for initiating the plan or steps required for backup functionality." 4. R1.4.2 - Suggest removing the term "support". The goal of this requirement is to return to full operations, not just operations support. 5. R1.5 - The need to return back to the primary control center is missing from this requirement. Suggest adding the following at the end of this requirement: "as well as the actions to be taken to return back to primary control center functionality." 6. R1.6 - As written, this requirement could be too strict and not allow for personnel flexibility. Suggest rewording the requirement as follows: "Identification of the required roles of involved personnel during the initiation and implementation of the plan or steps required for backup functionality and for the return to the primary control center." 7. R2 - This requirement could be confusing as written and additionally seems to be missing important information regarding the operating and monitoring of the system during the transitional period. Suggest rewording this requirement as follows: "Each Reliability Coordinator, Balancing Authority, Transmission Operator and Generator Operator with a centrally dispatched control center shall have a copy of its plan or steps required for backup functionality located in its primary control center and at the location fulfilling backup functionality, and any facility used for operating or monitoring the BES during the transition process." 8. R3 - We believe that this requirement is duplicative of Requirement R1. The applicability and any delegation of TOP tasks would already be covered by R1. Therefore we suggest removing Requirement R3.

#8 – Commenter	Yes	No	Comment
			9. R4 - Standards must be followed and adhered to at all times. Therefore the last phrase of this requirement: "... as required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator" is unnecessary and should be removed. 10. R5 - Standards must be followed and adhered to at all times. Therefore the last phrase of this requirement: "... sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively" is unnecessary and should be removed. 11. R9 - To be consistent with other reliability standards, and to allow the entity flexibility in defining roles of authority over Operating Plans, Processes, and Procedures, we suggest removing the last phrase "... by a manager" 12. R9.1 - Since backup functionality includes more elements than just "location, capabilities, and communication protocols", we suggest simplifying this requirement and simply ending the sentence after "... of any changes." 13. R10 - The phrase "any aspect of" should be removed from this requirement. It is not clear what this means and not necessary. 14. R11 - We believe this requirement could be worded better as follows: Each Reliability Coordinator, Balancing Authority, Transmission Operator and Generator Operator with a centrally dispatched control center shall have backup capability to operate for an indefinite period of time."

Response: 1) Operating Plan, Operating Process, and Operating Procedure are all defined terms in the currently approved NERC Glossary and were used based on those respective definitions. Therefore, no changes were made by the SDT.

2) The SDT changed to wording of R1.2 to**:** An ~~high level~~ overview of the elements required to support the backup functionality.

3) The SDT has removed R1.4.1 and re-worded R1.4: Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality. ~~including at a minimum:~~

4) The SDT has deleted R1.4.2.

5) The SDT has removed references for returning to the primary facility.

6) The plan needs to identify the personnel that will be involved with the backup. These may include operating, support, and management personnel. The wording of R1.7 has been changed to: Identification of the roles for ~~all involved~~ personnel involved during the initiation and implementation of the Operating Plan for backup functionality ~~and for the return to the primary control center.~~

<table>
<tr><th>#8 – Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td colspan="4">7) The SDT feels that the Operating Plan must be located at the primary and backup locations. Distribution of the plan to other locations is at the discretion of the entity. Therefore, the proposed change was not made to R2.
8) R3: The SDT feels it is necessary to point out that the registered TOP is responsible to ensure that operations required to maintain the reliability of the BES, including those they delegate, must be backed up. The SDT has changed the wording of R3 to: Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality ~~those operations~~ in its Operating Plan for backup functionality.
9) R4 and 5: The purpose of R4 and R5 is to make it clear that the plan must include whatever is required to comply with all reliability standards. The SDT received comments implying that standards be categorized and that compliance to only some standards be required in a backup configuration. That reinforces the SDT's original decision to make it clear that adherence to all applicable standards is required in backup configuration.
10) Operating Plan, Operating Process, and Operating Procedure are all defined terms in the currently approved NERC Glossary and were used based on those respective definitions. Therefore, no changes were made by the SDT.
11) By a Manager has been removed from the requirement. The revised document will state under the new R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~.
12) Saying "of any change" could imply anything. "Backup location, capabilities or communications" is more specific to changes in significant functionality.
13) R10 (now R7) deals with RC, BA, & TOPs while R4 is specific to the RC. The SDT has changed the wording in R10 (now R7) to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards.
R11 has been moved to R1.1: The location and method of implementation for providing backup functionality for a prolonged period of time.</td></tr>
<tr><td>Gainesville Regional Utilities</td><td>x</td><td></td><td>R1.4.1 This does not need to be addressed, Any Operational entity in NERC can recognize a reason to abandon their primary Control Center.(Fire, Avalanche, Forest fire, Flood, Tornado, No building, No Computer, GLeaking Gas, etc.) I believe this is not necessary at all R1.4.2 Same reason, when all in normal , we return to the primary facility. R.2 What is the reason to have the Operating plan at both places. Each operator ahs theoretically been trained yearly on the plan and should have an understanding of what is required. What more is needed? The entire SAR needs to addressed. What is required is a plan to continue operation in the case of a primary Control Center, How it is accomplished seems up for more discussion as towhat may be required for continued operation. This SAR as others viseems to view all entities that hav decided to have a back up center rather than a plan meet requirements that are no necessarily needed.</td></tr>
<tr><td colspan="4">**Response:** The SDT has removed R1.4.1 and re-worded R1.4: Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality. ~~including at a minimum:~~ The SDT has deleted R1.4.2.</td></tr>
</table>

#8 – Commenter	Yes	No	Comment
The SDT feels that the Operating Plan must be located at the primary and backup locations. Distribution of the plan to other locations is at the discretion of the entity. Therefore, the proposed change was not made to R2.			
Hydro One Networks, Inc.	x		Requirement R9 states that the Plan must be approved by a manager. Manager of what? This level of approval for such an important plan is too low. We suggest VP or higher. For review, we suggest an applicable "Operating/Control Room Manager".
Response: By a Manager has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. ~~reviewed and approved annually by a manager.~~			
Hydro Québec/TransÉnergie NPCC Regional Standards Cmte.	x		Drafting team should clarify the term "GOP centrally dispatched". The Drafting Team should focus on the reliability objective as opposed to how the objective is met.
ISO New England	x		The Drafting Team should focus on the reliability objective as opposed to how the objective is met.
Response: The GOP has not been included as an applicable entity in this Standard. "GOP centrally dispatched" refers to those GOPs that dispatch many dispersed plants from a central control center. FERC had in mind plants located across North America in multiple control areas. The SDT believes it has addressed the 'what' as opposed to the 'how'. The SDF has left it up to the entities to address how the requirements are implemented.			
IESO	x		R1 is written with the backup facility in mind. It needs revision if the backup plan is to a backup capability such as by transferring operational control to another operating entity. R2 - Adresses that the RC, BA and TOP shall have a copy of its operating plan to be physically located at both, the primary control facility and the back-up control facility. It does not address the issue of exchanging this information between the applicable entities. It is essential that the RC is aware of the TOP and BA's operating plans and backup centers - something akin to the system restoration plan - not sure if the RC should review and approve the backup operating plans of the the TOP and BA, but as a minimum, the RC should be provided with the appropriate information by the applicable TOP and BA entities. R3: It is unclear to us what this requirement aims to accomplish. If a responsible entity has to use other entities to implement its backup functionality, it will be explicitly included in its plan. R4 should be modified to require each RC to have an arrangement for backup

#8 – Commenter	Yes	No	Comment
			control facility or capability. This requirement will then be more succinct, as stringent, and provide the RC flexibility to make necessary business arrangements to provide backup capability. There is nothing especially important about the RC having its own backup control center or utilizing another RC's control center. It is possible that a third party might be willing to develop control capability to serve as a backup for multiple parties. R5 is really redundant to R1. If a BA and TOP must have a plan to have backup functionality, they have met Requirement 5. R9: We do not see the need to specify who in the responsible entity's organization should approve the plan (ref. approved by a manager). This is an internal business process that has nothing to do with reliability. If approval of a backup plan is required, then the responsible entities shall submit their plans to the RE for review and approval. The version 2 SAR of the subject matter references transmission owners (TOs) with transmission control centers as an applicable entity to this standard. The current draft of the standard is silent on such the applicability of TOs - was the omission deliberate? If it was, we do not see any statement or logic to this effect.

Response: R1 – The SDT does not feel that the requirement restricts moving control to another operating entity for backup. The only prescriptive requirement for backup is that the RC must have a backup facility but that the TOP and BA must have backup capability. Backup capability can be achieved by a backup facility or by contracted backup through another entity.

The SDT feels that the Operating Plan must be located at the primary and backup locations. Distribution of the plan to other locations is at the discretion of the entity. Therefore, no change was made to R2.

R3: The SDT feels it is necessary to point out that the registered TOP is responsible to ensure that operations required to maintain the reliability of the BES, including those they delegate, must be backed up. The SDT has changed the wording of R3 to: Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality ~~those operations~~ in its Operating Plan for backup functionality.

R4: The distinction between backup capabilities for RCs as compare to other entities arose from the FERC rulemaking relevant to this standard. FERC was emphatic that RCs have physical backup control centers. The SDT agrees that the emphasis should be on "what" as opposed to "how", and has changed the wording of the requirement to provide additional flexibility for RCs, but is constrained by FERC's direction on this point. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator.

#8 – Commenter	Yes	No	Comment
R5: Having both R1 and R5 is a key element of the modification of EOP-008. One of the main criticisms of EOP-008 was that it only required a plan, and did not sufficiently require that the plan be realistic, effective, and tested. The presence of R5 is to make clear that to merely have a plan is not sufficient. You must be able to demonstrate that you have the capability to maintain system reliability in your backup configuration. "By a Manager" has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~. The SDT does not believe that the TO needs to be included in this standard. Focus is on the TOP and not the TO. Inclusion in a SAR is not mandatory for inclusion in the standard.			
ISO/RTO Council Midwest ISO	x		In general, this requirement is overly detailed and broad. There are really only three basic requirements for establishing backup operational capability. Those three requirements are: 1. Have a plan 2. Test plan 3. Implement when needed. Any requirements beyond these three basic requirements will only detract from reliability because they will cause entities to focus on requirements outside of these basics. Many of the subrequirements in this standard are not requirements at all. Rather they are criteria or lead-in statements for other subrequirements. This is problematic because the FERC has established VRFs for subrequirements in the past that are really not requirements and is now requiring the establishment of VSLs for many subrequirements that are not requirements at all or may even be explanatory text. This draft standard is perpetuating this problem. Any subrequirements that are criteria should simply be listed as bullets under the requirement with the requirement specifying that it is subject to the following criteria. For instance, all subrequirements under R1 do not really have any requirement. They are simply a list of what should be included in the plan identified in R1 or explanatory text. Thus, many of these sub-requirements should simply become bullets. This would also aid in the establishment of multiple VSLs because an entity that has a plan but is only missing couple of the requirements might have a low VSL. Whereas an entity, not having a plan would then fall into the SEVERE VSL. R1.1 is not necessary but is simply a part of a plan. A plan doesn't exist if it doesn't identify where and how. This could be specified as a criterion for the

#8 – Commenter	Yes	No	Comment
			plan. R1.2 is unneccesary. First, high level is subjective. Requirements should not be subjective. Secondly, each of the sub-requirements under it will stand alone without R1.2. R1.3 should be modified. What it really needs to state is that the backup functionality needs to have current BES data. It should not be tied to what the primary control center has because the primay control center data may be out of synch with the BES. This would be a reason to utilize the backup functionality. R1.4 is not necessary. The subrequirements under it do an adequate job of spelling out the basic minumum requirements without the introductory statement that R1.4 is. A third criteria should be added that identifies who makes the decision to implement the back-up plan. R2 is not necessary if there is going to be timing requirements for bringing the backup functionality. It is a good idea but should not be a requirement. In effect, requiring the backup functionality to be functioning in x amount of time will cause the responsible entity to have the plan at their fingertips. Additionally, a properly trained system operator should be able to implement the plan without referring to the plan. R3 is a requirement that is an example of an attempt to write the standard for a every conceivable sitiuation and is not necessary. If a responsible entity has to use other entities to implement its backup functionality, it will be explicitly included or they will not have a plan that they can test. Thus, they will not meet requirement. R4 should be modified to require each RC to have arranged for the availability of back-up capability. This requirement will then be more succinct, as stringent, and provide the RC flexibility to make necessary business arrangements to provide back-up capability. There is nothing especially important about the RC owning its own backup control center or utilizing another RC's control center. It is possible that a third party that is not an RC might be willing to develop a control center to serve as a backup for multiple parties. As long as the requirement functionality is provided, why would this be a problem? The

#8 – Commenter	Yes	No	Comment
			requirement as written would preclude this satisfactory arrangement. R5 is really redundant to R1. If a BA and TOP must have a plan to have backup functionality, they have met Requirement 5. Let's not create an opportunity for double jeopardy. Requirement 8 and all of its subrequirements are not really requirements. It really is criteria for R1. Requirement 9 should remove the requirement to have the plan approved by a manager. This is really a business process requirement and does nothing to ensure reliability. Besides, Requirement 13 will cause this to happen anyway. Do you really think that the plan can be tested annually without a manager's approval? R10 and R11 is not really a requirement. It belongs as a criterion under R1.

Response: General – a) The SDT feels that those elements have been addressed but that the details provided will permit more consistency in applying the standards. b) The organization of the requirements was reviewed by the SDT. However, the use of bullets will be dictated by NERC format rules.

R1.1: Since the method of implementation is part of the Plan, the SDT feels it must be listed as a requirement.

R1.2: The SDT changed to wording of R1.2 to**:** An ~~high level~~ overview of the elements required to support the backup functionality.

R1.3: The SDT agrees that if the primary system is out of synch with the BES that that may be a reason for moving operations support to the backup. The SDT does not feel that the standard should be prescriptive to the point of detailing what the reasons are for leaving a primary control center. That should be detailed in each entity's plan.

The SDT has removed R1.4.1 and re-worded R1.4: Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality. ~~including at a minimum:~~ The SDT has deleted R1.4.2.

The SDT feels that the Operating Plan must be located at the primary and backup locations. Distribution of the plan to other locations is at the discretion of the entity. Therefore, the proposed change was not made to R2.

R3: The SDT feels it is necessary to point out that the registered TOP is responsible to ensure that operations required to maintain the reliability of the BES, including those they delegate, must be backed up. The SDT has changed the wording of R3 to: Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality ~~those operations~~ in its Operating Plan for backup functionality.

R4: The distinction between backup capabilities for RCs as compare to other entities arose from the FERC rulemaking relevant to this standard. FERC was emphatic that RCs have physical backup control centers. The SDT agrees that the emphasis should be on "what" as opposed to "how", and has changed the wording of the requirement to provide additional flexibility for RCs, but is constrained by FERC's direction on this point.

#8 – Commenter	Yes	No	Comment
R5: Having both R1 and R5 is a key element of the modification of EOP-08. One of the main criticisms of EOP-08 was that it only required a plan, and did not sufficiently require that the plan be realistic, effective, and tested. The presence of R5 is to make clear that to merely have a plan is not sufficient. You must be able to demonstrate that you have the capability to maintain system reliability in your backup configuration. R8 has been deleted as all entities now have the same 2 hour requirement. “By a Manager” has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~. R10 deals with RC, BA, & TOPs while R4 is specific to the RC. The SDT has changed the wording in R10 (now R7) to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards. R11 has been moved to R1.1: The location and method of implementation for providing backup functionality for a prolonged period of time.			
Madison Gas and Electric	x		R5 should be broken down into sub bullets, ie: R5.1, monitoring, R5.2, Control, R5.3, Logging, ect. R9 The last three words should be deleted "by a manager". Some entities may not have "manager" in the title of the position that writes and implements the Operating Plan. R10, the last sentence uses the words "any aspect" and needs to be removed. FERC Order 693, para. 663 states "... and the provision of a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center". The statement "any aspect" implies we can use nothing from the primary control center. What if I rely on security cameras to ensure Cyber security of both sites when dealing with physical security perimeters? Even though I may not be using the primary site for control I still have to protect it. I suggest new wording of "... does not depend on the primary control center for its functional operations". Or words to that effect. It is helpful to the Utility Industry if Measurements, Compliance, Data Retention, VSL's, etc. are in the draft standard. This allows us to see the whole picture of what is being proposed. It may even speed up the SAR process.
Response: R5: The phrase you are referring to is intended to clarify what types of capabilities are anticipated, not as an exhaustive list of required capabilities. If the SDT made the suggested change, each listed activity would become mandatory. Also, by implication any other activity required for reliability but not included on the list would be waived. The goal of the SDT with this requirement was to make clear that all reliability standards need to be adhered to in backup configuration and to provide examples of capabilities that would be anticipated to meet			

#8 – Commenter	Yes	No	Comment
those requirements. If an entity could meet all reliability standards without utilizing one of the items in this list they will not have violated R5 as written. If an entity has all these capabilities but still does not have what they need to comply with the standards then they would be in violation of R5 as written. This was the intent of the SDT. Changing the requirement as suggested would significantly change the impact of these two scenarios in a way the SDT believes would make it less appropriate. "By a Manager" has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~. R10 deals with RC, BA, & TOPs while R4 is specific to the RC. The SDT has changed the wording in R10 (now R7) to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards.			
Manitoba Hydro Energy Board	x		Requirement R1.1 is too loose and is open to interpretation. Does R1.6 include the roles of support personnel including field personnel that may be required to staff stations during the transfer?
Response: R1.1 – The SDT feels that the requirement should not prescribe how a location or the method for backup is selected. Therefore, the requirement will remain. R1.7 – Who is involved is left up to the entity.			
Midwest Reliability Organization	x		During the transitional period were neither the primary or the backup control center are fully functionable, should the system operator have a copy of the transitional operating plan, a copy of the system one lines, and a list of all entities that they need to notify of a change in operating location? For example, lets say the primary control center is not functionable. The system operators become mobilized to make their way to the backup control center. They have everything they need, laptops, sattellite phones, etc but they don't have a copy of the transitional operating plan, a copy of the system one lines, and a list of all entities that they need to notify of a change in operating location until, they get to the back up control center. What if they are not able to get to the backup control center, but could wirelessly access the backup control center capabilities, thus allowing them to perform but in a limited fashion since they don't have the transitional operating plan, a copy of the system one lines, and a list of all entities that they need to notify of a change in operating location? Thus, the SDT should address the transitional period in a more developed fashion perhaps allowing the system operators to operate from another location other than the backup control center if need be found and the system operators have that capability. R9. Each Reliability Coordinator, Balancing Authority, and applicable

#8 – Commenter	Yes	No	Comment
			Transmission Operator, shall have its Operating Plan for backup functionality reviewed and approved annually by a manager. The reference to the manager should be removed. NERC should only be concerned with having the RC, BA, and TOP annually review its plan. Requiring approval of anything internal is outside the scope of a NERC reliability standard, though they have used this concept in other standards.
Response: Comments regarding transition period: The SDT agrees that these would be prudent steps for most utilities to take during implementation of a transition to a backup facility and they would be important components of most Operating Plans for backup functionality. However the SDT believes it is important to specify what needs to be accomplished as opposed to the manner in which it needs to be accomplished and to establish a standard that can be applied to virtually all relevant organizations. Some utilities might accomplish their backup functionality without the physical movement of people (such as allowing another facility and staff to take over their responsibilities) in which case this requirement would not be applicable. The relevant sections of this standard require that the utility have a complete plan, that they can transition to the backup configuration in a reasonable amount of time, and that they contact appropriate parties during the transition. It is left to each utility to establish the best way to achieve those goals in its specific situation. Although most will include the steps you mention, the SDT believes the inclusion of those items in the standard would provide too much detail and inappropriately limit the flexibility of utilities to choose the most effective way to achieve the goals of the standard. "By a Manager" has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~.			
Nebraska Public Power District	x		Paragraph A.5. - Recommend a minimum of 36 months to implement the requirements in the standard after the effective date before the standard is auditable. Paragraph B.R9. - Delete, "by a manager". Each entitity should decide who has review and approval authority for its Operating Plan. Paragraph B.R9.1. - Requiring the Operating Plan to be updated and re-approved within sixty calendar days of any change is too restrictive. Major changes would require an update to the plan, but most changes could wait for the annual review. Paragraph B.R11. - Requiring a Backup Facility to be capable of operating for an indefinite period of time increases the complexity and adds unnecessary costs to the facility. Is this requirement mandating training facilities at the backup, including simulators, plus all the support staff for a Control Center. These functions are best addressed through an interium plan developed after the event

#8 – Commenter	Yes	No	Comment
			occurs; then, permanent facilities implemented with a plan to restore the primary. The actual situation that occurs will dictate how much and to what extent these are needed. General Comment: Our utility has spent a considerable amount on our primary facility to harden the facility and provide redundancy. Requiring us to invest in a fully operative backup facility redirects funding from needed infrastructure improvements in other areas. The actual probability and risk of needing a backup facility are very minimal, compared to transmission infrastructure improvements that clearly will provide value through increased ratings and reliability. Recommend the existing NERC requirements to have a plan to continue operations in the event its control center becomes inoperable be retained and the new requirements for a fully functional backup facility be eliminated. If this recommendation is not implemented, please provide justification from actual situations why these requirements are required.
Response: The Implementation Plan has been submitted with the second posting – and it indicates that entities will have at least 2 years to become compliant – starting with the date that the standard is approved by applicable regulatory authority approval. "By a Manager" has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~. R9.1 (now R6.1) – The requirement is specific to changes in location, capabilities or communication protocols. Changes would normally be planned ahead of time before the changes were made. The SDT considers 1 year too long. R11 – The SDT believes that it is important to realize that the length of time that you may be at your backup can't be predicted and that the use of the term 'prolonged' is appropriate. The plan should be for the long-term. An entity must be prepared to achieve compliance and maintain the reliability of the BES while in a backup mode. R11 has been moved to R1.1 and the term indefinite has been changed to 'prolonged'. The location and method of implementation for providing backup functionality for a prolonged period of time. General Comment: Even though the probability is very low, and you have a hardened Primary facility, there still needs to be a requirement for a backup plan for the loss of Primary functionality. The requirement does not say a backup facility - the requirement is backup functionality, therfore one could contract for service .			
Northeast Utilities	x		R9.1 "...within sixty calendar days of any changes to the backup location, capabilities, or communication protocols." is wide open. It seems there could be changes made that improve capabilities or communication protocols that would not meet the threshold of a revision to the plan, such as a tool added to the primary center that works similarly at the Backup Center. The words "any changes" are too broad, possibly replace with "significant changes that impact the Operating Plan….." or similar.

#8 – Commenter	Yes	No	Comment
Response: R9.1 (now R6.1) – The requirement is specific to changes in location, capabilities or communication protocols. Significant changes would normally be planned ahead of time before the changes were made. The requirement has been changed and replaces 'communication protocol' with 'contact information'. The update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to the backup location, capabilities, or ~~communication protocols~~ contact information.			
Oncor Electric Delivery Company	x		Requirement R3 is a step in the right direction. The intent is to be sure that local control centers that provide significant BES operating activities but which are not TOPs themselves also have backup capability. The requirement as written is subject to significant interpretation and it isn't clear whether the requirement achieves the desired outcome. For example, one interpretation would be that the TOP backup plan has to consider being able to operate with the local control center through its backup plan, but a more robust interpretation would address whether the backup facility plan of the TOP has also taken care of the loss of the primary control center for the local control center. This issue would typically arise when a Transmission Owner operates a primary control center that is important to BES reliability, but which is not themselves a Transmission Operator. The direct method would be to make these Transmission Owners a responsible entity. However, if the intent is to get to this concern through the Transmission Operator, then additional clarity in R3 is necessary. A very important issue that must be dealt with in this standard is the issue of enforcement of this standard following loss of the primary control center. There are two distinct dimensions to this issue. One is that during the transition period from the primary facility to the backup capability it needs to be recognized that not all reliability functions will be able to be accomplished. Specific waiver from compliance is very important during this transition period. Unless such a waiver is provided, the standard will essentially require that zero transition time is allowed between loss of primary control center and full functionality of backup capability. Such a requirement would essentially require a fully staffed hot backup capability at all times. Oncor believes such a requirement will be too expensive and not warranted. A second dimension to this compliance concern follows the loss of the primary control center itself. After the backup capability is fully functioning, compliance with all reliability standards would be expected, but the concern is whether compliance with EOP-008 itself would still be required. Unless it is clear that the provision of a backup capability is not required during the period that the primary capability has been lost, the result will be that a backup to the backup capability must be provided at all times. Oncor strongly believes that there is no credible reliability argument that would indicate that

#8 – Commenter	Yes	No	Comment
			such a 3 deep backup capability is warranted, and without such a waiver the standard would impose unreasonable costs on the industry.

Response: R3: The SDT feels it is necessary to point out that the registered TOP is responsible to ensure that operations required to maintain the reliability of the BES, including those they delegate, must be backed up. The SDT has changed the wording of R3 to: Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality ~~those operations~~ in its Operating Plan for backup functionality.

The SDT has addressed the issue of what happens following the loss of a control center in the revised R4 & R5.

R4**:** Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator.

R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively.

#8 – Commenter	Yes	No	Comment
PJM Interconnection	x		We suggest requirement 8 be rewritten to read; "For each RC, TOP and BA, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations." R8.1 and R8.2 can be eliminated since the time requirements suggested above are the same for BA, TOP, RC.

Response: Requirement R8 has been deleted. The requirement to identify the entities that must be notified if there is a "change in operating locations" is now in R1.6.1 as part of the Operating Plan. R8.1 and R8.2 have been deleted.

#8 – Commenter	Yes	No	Comment
Santee Cooper	x		We are unsure as to the definition of what starts the transition period and what ends the transition period to the backup control center. We believe further detail is required. Regarding R11 - what is an "indefinite period of time" and what would be a reasonable measure? Regarding R4 - We believe the term "replicates" should be removed, as this may

#8 – Commenter	Yes	No	Comment
			not be physically possible. Perhaps a distiction between types of functionality required would be more appropriate. We certainly disagree with any thought process that would require continual staffing of the backup control center. If entities can invoke their backup plan and have backup functionality with two to three hours, this should be sufficient, especially given the odds of the number of times it will be needed.
Response: Transition starts with the event that results in the loss of functionality at the primary control center and ends with the restoration of functionality at the backup. R11 has been moved to R1.1 and the term 'indefinite' has been changed to 'prolonged'. The location and method of implementation for providing backup functionality for a prolonged period of time. R4 Comment Paragraph 1: We interpret the comment as inferring a requirement to duplicate functionality of the primary control center beyond that which is required to maintain compliance with Reliability Standards. The requirement has been rewritten to make clear that such is not the intent. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator. Paragraph 2: It is not the intent to require a continually staffed backup control center. The SDT does not believe the draft language can be read to imply such a requirement.			
Sierra Pacific Resources Transm.			Use of "Plan", "Process" and "Procedure": I found myself a bit confused as to the terminology used here. The Standard starts out by defining that there shall be an Operating Plan for the backup center, which is to include a number of items. Later, the Standard introduces the terms "Operating Process" (R1.4 and R1.5) and even "Operating Procedure" (R8.1, R8.2). Many will interpret these terms to be synonymous unless there is some distinction provided in the Standard. R9 Annual Review and Approval by a "manager": This term seemed a bit loose to me as I reveiwed the Standard. As it is not a defined term, it is left open to interpretation as to what level individual can act as the "manager". Perhaps there should be some clarification such as "...a manager having functional responsibility for Control Center Operation". R10 Dependency Upon Primary Control Center: This Requirement prohibits any dependency upon the primary center for any aspect of the backup center operation. Such a strict Requirement may necessitate a transition period to achieve compliance. Most BUCC operations have some level of dependency upon the primary, and we strive to minimize that. The BUCC will likely have a

#8 – Commenter	Yes	No	Comment
			reduced, but adequate, level of functionality if the primary were to be completely destroyed, but might have far greater capability if some of the primary control center facilities remain active. Note that this Standard does not specifically prescribe how much visiblity or functionality the BUCC must have. Document Simplification Suggestions: Since R1 describes the Operating Plan and its minimum included items, I would suggest moving the text of R8 into a sub-item of R1, as R1.7. The draft R8 talks about another item that is to be included in the Operating Plan. The sub items R8.1 and R8.2 don't seem to bear any relationship to the parent R8. These Requirements are for situational awareness if the implementation of the BUCC operation is to last more than 2 hours, and they fit better as sub-items under R7, which speaks to the transition period. I'd therefore suggest moving these under R7 as R7.1 and R7.2.
Response: Operating Plan, Operating Process, and Operating Procedure are all defined terms in the currently approved NERC Glossary and were used based on those respective definitions. Therefore, no changes were made by the SDT. R8 has been deleted and all applicable entities now have the same time requirement. "By a Manager" has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~. The SDT has changed the wording in R10 (now R7) to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards. The SDT did move the intent of R8 into R1.6.1. R8.1 and R8.2 were deleted as the revised standard requires all responsible entities to have a plan to fully implement its backup plan and get backup functionality up and running that is less than two hours.			
SPP ORWG	x		In Requirement 9 add the following phrase after manager: …responsible for the operation of the primary control center. We would suggest that R2 be expanded to require copies of the Operating Plan be shared with all entities/locations having an active role in the plan.
Response: "By a Manager" has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality			

#8 – Commenter	Yes	No	Comment
~~reviewed and approved annually by a manager~~. R2: The SDT feels that the Operating Plan must be located at the primary and backup locations. Distribution of the plan to other locations is at the discretion of the entity. Therefore, the proposed change was not made to R2.			
WECC Operating Practices Subc.	x		Clarity needs to be added to R 9.1 regarding the definition of "communication protocal"? For example, entities do not want to have to update the operating plan for changes such as an RTU communication protocol.
Response: The key phrase is 'backup functionality.' If the RTU communication protocol significantly affects the Backup functionality then it needs to be reflected within the plan in the required timeframe. R9.1 has been changed and 'communication protocols' has been replaced with 'contact information'. The update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to the backup location, capabilities, or ~~communication protocols~~ contact information.			
Allegheny Power		x	
Comision Federal de Electricidad		x	
MA Dept. of Public Utilities			No comment.
NY State Dept. of Public Service			No comment.
PacifiCorp		x	
Pacific Gas and Electric Company			No comment.
PS Commission of South Carolina		x	
Sacramento Municipal Utility Dist.		x	No other comments at this time.
Sierra Pacific Power Company			No comment.
Tampa Electric Company		x	
Xcel Energy			No comment.
Response: Thank you for your response.			