Comment Report

Project Name:	2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2
Comment Period Start Date:	6/30/2016
Comment Period End Date:	8/15/2016
Associated Ballots:	2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 IN 1 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 NBP IN 1 NB 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 IN 1 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 NBP IN 1 NB 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-008-2 IN 1 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-008-2 NBP IN 1 NB

There were 64 sets of responses, including comments from approximately 58 different people from approximately 54 companies representing 9 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-005-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

2. Do you agree with the retirements proposed in EOP-005-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

3. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

4. Do you agree with the retirements proposed in EOP-006-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

5. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-008-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

6. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

7. Please provide any additional comments for the EOP Standard Drafting Team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Portland General Electric Co.	Angela Gaines	3	WECC	PGE - Group 1	Angela Gaines	Portland General Electric Company	3	WECC
					Barbara Croas	Portland General Electric Company	5	WECC
					Scott Smith	Portland General Electric Company	1	WECC
					Adam Menendez	Portland General Electric Company	6	WECC
Chris Gowder	Chris Gowder		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utility Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Stan Rzad	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steve Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC

					Mark Brown	City of Winter Park	4	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	9	FRCC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
ACES Power Marketing	Colleen Campbell	6	NA - Not Applicable	ACES Standards Collaborators	Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Chip Koloini	Golden Spread Electric Cooperative, Inc.	5	SPP RE
					Greg Froehling	Rayburn Country Electric Cooperative	3	SPP RE
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Paul Mehlhaff	Sunflower Electric Power Corporation	1	SPP RE
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bob Solomon	Hoosier Energy Rural Electric Cooperative,	1	RF

						Inc.		
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	Madison Gas & Electric	3,4,5,6	MRO
					Chuck Wicklund	Otter Tail Power Company	1,3,5	MRO
					Dave Rudolph	Basin Electric Power Cooperative	1,3,5,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Jodi Jenson	Western Area Power Administration	1,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Mahmood Safi	Omaha Public Utility District	1,3,5,6	MRO
					Shannon Weaver	Midwest ISO Inc.	2	MRO
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Brad Perrett	Minnesota Power	1,5	MRO
					Scott Nickels	Rochester Public Utilities	4	MRO
					Terry Harbour	MidAmerican Energy Company	1,3,5,6	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,4,5,6	MRO

					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
Con Ed - Consolidated Edison Co. of New York	Kelly Silver	1	NPCC	Con Edison	Kelly Silver	Con Edison Company of New York	1,3,5,6	NPCC
					Edward Bedder	Orange and Rockland Utilities	NA - Not Applicable	NPCC
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Robert Schaffeld	Southern Company Services, Inc	1	SERC
					John Ciza	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Robert Coughlin	Robert Coughlin		NPCC	SRC	Kathleen Goodman	ISO-NE	2	NPCC
					Ben Li	IESO	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Mark Holman	PJM	2	RF
					Liz Axson	ERCOT	2	Texas RE
					Charles Yeung	SPP	2	SPP RE
					Ali Miremadi	CAISO	2	WECC
					Terry Bilke	MISO	2	RF
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC no Dominion and NYISO	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York	4	NPCC

						Power Authority		
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Silvia Parada Mitchell	NextEra Energy	4	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kathleen M. Goodman	ISO-NE	2	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Don Schimtt	Nebraska Public Power	1,3,5	SPP RE

						District		
					Jerry McVey	Sunflower Electric	1	SPP RE
					Jim Nail	Independence Power and Light	3	SPP RE
					Michelle Corley	Cleco	1,3,5,6	SPP RE
					Robert Gray	Board of Public Utilities (BPU)	NA - Not Applicable	NA - Not Applicable
Lower Colorado River Authority	Teresa Cantwell	1		LCRA Compliance	Michael Shaw	LCRA	6	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Teresa Cantwell	LCRA	1	Texas RE

1. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-005-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

While AEP supports the overall direction and efforts of this project team, we have chosen to vote negative on EOP-005-2. Our negative vote is driven by our concerns regarding the obligation to reissue the entire restoration plan 30 days prior to the Transmission Operator's implementation of planned System modifications, even for minor revisions.

The proposed thirty-day window in R4 would be a difficult time frame to meet in many instances. Many jobs that are not directly created for the restoration plan, yet affect its restoration sequence, are often scheduled. However, these jobs are often rescheduled due to weather, system conditions or conflicting scheduled outages. Due to the possibility of multiple system improvements that may occur, which are either completed ahead of schedule or delayed during those 30 calendar days, we believe an accurate plan could not be maintained for the system operators. One option would be an addendum sheet that would contain the incremental changes and their implementation date, which could then be followed by a quarterly update to the restoration plan. This addendum sheet would be provided to all of the RTO and all the affected parties.

As the restoration plan is a voluminous document, AEP proposes to communicate with the RC only on the incremental changes (which could be only few sentences) rather than reissuing the entire, voluminous document.

AEP suggests modifying the proposed revision of R4 as suggested above, as well as completely eliminating the proposed R4.2.

Likes 0	
Dislikes 0	
Response	

Kelly Silver - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	No
Document Name	
Comment	

The definition of a Balancing Authority is "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." During restoration, the local TO or TOP isolated island operations are not synchronized to the interconnection so they cannot support the interconnection frequency. Therefore, by definition, EOP-005-3 Parts 1.9 and 8.5 which refer to transference of Balancing Authority should be removed. Balancing Authority functions will always reside with the designated Balancing Authority, even when operating as an isolated island. EOP-005-3 Parts 1.9 and 8.5 which refer to transference of Balancing Authority authority should be removed. They are not universally applicable, and where applicable a variance should be made. Balancing Authority functions will always reside with the designated Balancing Authority.

Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	

In the first sentence of Requirement R1 the proposed revision is to have the Requirement read that “Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator.” However, to be consistent with the language that is already being proposed for EOP-006-3 Requirement R1 the revision should read that each Transmission Operator “shall develop, maintain and implement” a restoration plan approved by its Reliability Coordinator. The wording proposed for EOP-006-3 should be used in EOP-005-3.

There is no reference to the formation of a BES island in EOP-005-3 Requirement R1 as there is in EOP-006-3 Requirement R1 (“or an energized island has been formed on the BES”). The Drafting Team should consider its inclusion in EOP-005-3 or its removal from EOP-006-3.

Requirement R4 should be clarified to limit the type of System modifications that would require an update to the restoration plan solely to permanent System modifications that would change the Transmission Operator’s ability to implement its restoration plan.System modifications should be clearly defined. It should be limited to transmission and generation components. A definition of System modification should be added to the NERC Glossary.

EOP-005-3 Parts 1.9 and 8.5 which refer to transferring of Balancing Authority authority should be removed. They are not universally applicable, and where applicable a variance should be made. Balancing Authority functions will always reside with the designated Balancing Authority.

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	

Xcel Energy feels that the verbiage change from "Annual" to "at least every 15 months" in R3 and R8 is unnecessary, does not improve the standard, and is not consistent with numerous other standards that currently contain "Annual" requirements.

Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

The language to "implement" the system restoration plan has the potential to create confusion within the industry. Implementation of the a restoration plan would require a system outage to be compliant. Language should be adjusted to represent the intent of the SDT.

Likes 0	
Dislikes 0	
Response	

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	

Although generally supportive of the revisions made by the drafting team, the NSRF has concerns with the following requirements.

1.) **R1** - In consideration that developing and implementing a restoration plan represents two separate actions required by TOPs, we recommend the following change to R1 in order to clarify when the restoration plan is intended to be implemented.

“Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to allow for restoring the Transmission Operator’s System following a Disturbance in which one or more areas…”

2. R8.5 needs to reworded. We understand the intent, which we agree with. Recommend from “Transition to Balancing Authority for Area Control Error and Automatic Generation Control” to “Transition back to Balancing Authority control for Area Control Error and Automatic Generation Control”. This clearly states that a hand-off of responsibilities is warrented at the end of system restoration.

3.) We recommend retaining the current R1 language “to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator’s System.” We are concerned that deletion of the qualifying clause at the end of R1 will require an expansion of scope for all current Blackstart restoration plans.

Without the qualifying language, Transmission Operators are required to have a restoration plan for restoring the TOP’s System, with Blackstart Resources required to restore the “shutdown area to service” without any qualification or limit to the “shutdown area” short of the TOP’s entire BES “System.”

In the worst case scenario when there is a total black out of the system the plan would have to be quite large. It would be difficult to cover all the variables and conditions that could likely be encountered. Maintenance of such a plan would be very difficult leading to compliance issues.

Possible alternative language: “The restoration plan shall allow for restoring the Transmission Operator’s System following a disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to start generation for the restoration of the shutdown area to service.”

4.) The replacement of “annual” with “at least once each 15 calendar months” in R3 & R8 introduces additional unnecessary administrative tracking requirements, restricting entities to submission or training, respectively, within a moving 4-month compliance window vs. the current flexibility of the entire calendar year. Demonstrating compliance would now require comparison with the previous completion date vs. showing annual accomplishment.

What is the justification for this complication? Preventing a possible interval of up to 23 months? What is the reliability risk of a 23-month interval vs. a 15-month interval? Such an occurrence would be self-correcting under the current annual requirement. If R3/8 were accomplished in Jan. 2018, and not again until Dec. 2019, the next occurrence would be required in Dec. 2020, no more than 12 months later, and earlier than the proposed new requirement of 15 months.

5. R4 – With Transmission Operators required to submit their updated restoration plan to the RC “no less than 30 calendar days prior to…planned System modifications”, we are concerned the new timeframe may require TOPs to maintain two versions of their restoration plan in the control room due to confusion in terms of which restoration plan is considered valid while awaiting energization of a planned System modification.

As an example, a System modification impacting the restoration plan is scheduled to occur on September 1st so a TOP submits an updated plan to their RC on July 29th. The RC reviews and approves the plan on August 19th. To comply with EOP-005 R2 and R5 which require the TOP to provide the plan to System Operators and identified entities “prior to the effective date”, the TOP distributes the newly approved plan on August 24th. Since the System modification is still over a week away from energization, which RC-approved restoration plan is considered valid?

6. R4 – Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect permanent System modifications, …..

By inserting the previously included word “permanent” it is clear that the intent is for those permanent modifications that affect the restoration plan and not those temporary modifications that may come about due to temporary reconfiguration of the system such as may occur due to storm damage, etc.

Likes 0	
Dislikes 0	

Response

Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF

Answer	No
Document Name	

Comment

R1: Recommend retaining “to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator’s System.” Helps to provide guidance for an end point to the plan.

R8. Deletion of Requirement 8 is not advised. The Reliability Coordinator must play a defined role when establishing ties. It’s the RC’s role to ensure each Transmission Operator’s System is ready for the connection.

R8.5 The Restoration Plan is not intended to go to the extent of having ACE nor AGC available. If this is required significant addition to the Restoration Plans is foreseen as not enough of the system is restored to the point where ACE and AGC will be viable. The generating units will not be in a range to be placed on AGC in the plans as written today. If training for ACE and AGC is required, then wouldn’t the restoration plans need to support same? If 8.5 is retained, recommend this requirement be trained in conjunction with a Balancing Authority Operator. This may require expanding applicability of

EOP-005 to BA?.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins with the comments of the IRC Standards Review Committee (SRC). ERCOT also offers this additional point: The SDT should add a conditional phrase to the language of Requirement R1 to clarify that the restoration plan will only be implemented during an actual blackstart event. Otherwise, the requirement as written indicates that the entity must have implemented a restoration plan absent an event. As such, we recommend language that clarifies this: "Each Transmission Operator shall develop, maintain, and, in the event of a Disturbance, implement a restoration plan…"	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	No
Document Name	
Comment	
Austin Energy (AE) requests the SDT provide additional clarity regarding the TOP's scope of responsibility similar to EOP-006 R1. AE offers this suggestion: R1. Each Transmission Operator shall develop a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the BES shuts down and the use fo Blackstart Resources is required to restore the affected area to service. Each Tranmission Operator shall implement its restoration plan when necessary to restore the portion of the BES under its control and interconnect with neighboring areas. If the Transmission Operator cannot execute the restoration plan as expected, it shall use its restoration strategies to facilitate restoration. AE requests the SDT clarify R4.2. As written currently, it may imply restoration plans must be updated prior to any outage including short-term maintenance outages. AE does not believe such an action is necessary. Other Transmission Operators and the Reliability Coordinator are notified of temporary outages through local outage-related requirements. Additionally, AE does not believe the requirement clearly defines when the plan must be updated.	

AE makes the following suggestions:

R4. Each Transmission Operator shall update, and submit to its Reliability Coordinator for Approval, its restoration plan to reflect System modifications which change its ability to implement its restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modification; and

4.2. No less than 30 calendar days prior to the date on which the Transmission Operator energizes a permanent System configuration change.

Likes 0	
Dislikes 0	

Response

Tina Garvey - Austin Energy - 4

Answer	No
Document Name	

Comment

I support the comments of Andrew Gallo.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

Most training is conducted on a yearly basis, with certain training required every year. For example, TVA has three cycle training classes lasting seven weeks each cycle in order to get all of the operators through the training. At times it makes more sense to conduct specific required training in one cycle versus another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if the System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, “at least once each 15 calendar months” it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training was required “once per calendar year.” That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

The revision to EOP-005 R8 adds the requirement R8.5 - “Transition to Balancing Authority for Area Control Error and Automatic Generation Control.” TVA agrees with the addition of this requirement and thinks required training in this area would be good for the industry. One possible concern with the proposed language has to do with when the TOP returns control of the BA Area back to the BA, the BA isn’t necessarily going back to Automatic

Generation Control right away. Our suggestion would be to reword R8.5 to say, “Transition to Balancing Authority ensuring adequate Area Control Error (ACE) configuration and generation control.”

Likes 0	
Dislikes 0	

Response

Andrew Pusztai - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

Comment on R3 & R3.1: ATC recognizes that FERC previously approved the retirement of R3.1. However, we recommend that the R3 language be changed to not require annual submission of the entire plan if no material have occurred. Requiring submission and RC response for these instances provides, in ATC’s opinion, little value to reliability. The standard should permit notification to the RC that the plan has not changed from the previous submission. As such, we propose that R3 be modified to read:

Each Transmission Operator shall review its restoration plan *for any substantive change,* and submit it to its Reliability Coordinator at least once each 15 calendar months on a mutually agreed, predetermined schedule *or notify its Reliability Coordinator that no sustative change occurred requiring approval of a new version of the TOP restoration plan*.

Comment on R4: As the SDT notes, TOPs should not have to submit a revised restoration plan to the RC to account for temporary changes to the system. However, the proposed edits to the standard language do not provide this clarity because R4.2 pulls in all planned modifications to the system, such as temporary configurations for construction or maintenance, that are not in view under the current EOP-005-2 R4 language. The new language pulls in these types of situations since the actual implementation of the plan in an event may be affect by construction activities (e.g., lines temporarily tied together) such that a different line gets used for a restoration path covered by R1.5 (i.e. very specific switching paths have to be identified in the plan). Today’s R4 is better suited to the realities of temporary construction activities where the plan does not need to be submitted to the RC for review because the plan already conceives of the potential for paths to not be available (see EOP-005-2 R7) such that the TOP would then use its restoration strategies to accomplish the restoration task. The SDT changes do not improve reliability. Rather, they add administrative burden without reliability benefit.

R4 recommendation: language should read “reflect *permanent* System modifications” to avoid pulling in temporary configurations needed to support maintenance or construction.

R4.1 recommendation: language should read “unplanned *permanent* System modifications” to avoid pulling in temporary configurations needed to support maintenance or construction.

R4.2 recommendation: language should read “planned *permanent* System modifications” to avoid pulling in temporary configurations needed to support maintenance or construction.

Comment on new R8.5: The proposed language for R8.5 is too specific for the standard. ATC recommends that R8.5 just read, “Transition to Balancing Authority”.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements. R1 should require a plan and define what needs to be in the plan. The proposed R1 should be modified to replace “develop and implement” with “have”. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan.

In R4 we request the re-insertion of the word ‘permanent’ into the requirement regarding the need to update the plan. Specifically the plan should be updated and re-submitted for approval upon ‘permanent’ System modifications. R4.1 and R4.2 should also get some additional language clarifying that the updates should only be made for ‘permanent’ system modifications. As stated, they require updates to be made for ‘any’ system modification no matter how small or impactful.

R6 should be modified to clarify that the dynamic simulation or testing requirement only applies to the initial Cranking Path from the Blackstart Resource to the next generator including whatever stabilizing loads are required. As written it could be interpreted that dynamic simulation/testing is required to verify that the loads (R6.2) and generation (R6.3) have the capability to control voltages and frequency within acceptable operating limits to accomplish the intended function of the plan. The intended function of the plan is outlined in R1 and includes transferring authority back to the BA. It would be unduly burdensome to perform dynamic simulations for each step in the process to get to this point. Also, it would be impossible to perform an actual test of the plan to this point since it would require creating a blackout to accomplish.

In the data retention section for R1, it is not clear what the change to ‘monitoring activity’ means. It previously clearly stated data must be kept since the last ‘compliance audit’. ‘Monitoring activity’ is undefined and may include spot checks, audits, or any number of monitoring actions. The corresponding language in EOP-006-3 still says data must be kept since the last compliance audit. We recommend changing the language back to match EOP-006-3.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements. R1 should require a plan and define what needs to be in the plan. The proposed R1 should be modified to replace “develop and implement” with “have”. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan.

In R4 we request the re-insertion of the word ‘permanent’ into the requirement regarding the need to update the plan. Specifically the plan should be updated and re-submitted for approval upon ‘permanent’ System modifications. R4.1 and R4.2 should also get some additional language clarifying that the updates should only be made for ‘permanent’ system modifications. As stated, they require updates to be made for ‘any’ system modification no matter how small or impactful.

R6 should be modified to clarify that the dynamic simulation or testing requirement only applies to the initial Cranking Path from the Blackstart Resource to the next generator including whatever stabilizing loads are required. As written it could be interpreted that dynamic simulation/testing is required to verify that the loads (R6.2) and generation (R6.3) have the capability to control voltages and frequency within acceptable operating limits to accomplish the intended function of the plan. The intended function of the plan is outlined in R1 and includes transferring authority back to the BA. It would be unduly burdensome to perform dynamic simulations for each step in the process to get to this point. Also, it would be impossible to perform an actual test of the plan to this point since it would require creating a blackout to accomplish.

In the data retention section for R1, it is not clear what the change to ‘monitoring activity’ means. It previously clearly stated data must be kept since the last ‘compliance audit’. ‘Monitoring activity’ is undefined and may include spot checks, audits, or any number of monitoring actions. The corresponding language in EOP-006-3 still says data must be kept since the last compliance audit. We recommend changing the language back to match EOP-006-3.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements. R1 should require a plan and define what needs to be in the plan. The proposed R1 should be modified to replace “develop and implement” with “have”. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan.

In R4 we request the re-insertion of the word ‘permanent’ into the requirement regarding the need to update the plan. Specifically the plan should be updated and re-submitted for approval upon ‘permanent’ System modifications. R4.1 and R4.2 should also get some additional language clarifying that the updates should only be made for ‘permanent’ system modifications. As stated, they require updates to be made for ‘any’ system modification no matter how small or impactful.

R6 should be modified to clarify that the dynamic simulation or testing requirement only applies to the initial Cranking Path from the Blackstart Resource to the next generator including whatever stabilizing loads are required. As written it could be interpreted that dynamic simulation/testing is required to verify that the loads (R6.2) and generation (R6.3) have the capability to control voltages and frequency within acceptable operating limits to accomplish the intended function of the plan. The intended function of the plan is outlined in R1 and includes transferring authority back to the BA. It would be unduly burdensome to perform dynamic simulations for each step in the process to get to this point. Also, it would be impossible to perform an actual test of the plan to this point since it would require creating a blackout to accomplish.

In the data retention section for R1, it is not clear what the change to 'monitoring activity' means. It previously clearly stated data must be kept since the last 'compliance audit'. 'Monitoring activity' is undefined and may include spot checks, audits, or any number of monitoring actions. The corresponding language in EOP-006-3 still says data must be kept since the last compliance audit. We recommend changing the language back to match EOP-006-3.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements. R1 should require a plan and define what needs to be in the plan. The proposed R1 should be modified to replace "develop and implement" with "have". R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan.

In R4 we request the re-insertion of the word 'permanent' into the requirement regarding the need to update the plan. Specifically the plan should be updated and re-submitted for approval upon 'permanent' System modifications. R4.1 and R4.2 should also get some additional language clarifying that the updates should only be made for 'permanent' system modifications. As stated, they require updates to be made for 'any' system modification no matter how small or impactful.

R6 should be modified to clarify that the dynamic simulation or testing requirement only applies to the initial Cranking Path from the Blackstart Resource to the next generator including whatever stabilizing loads are required. As written it could be interpreted that dynamic simulation/testing is required to verify that the loads (R6.2) and generation (R6.3) have the capability to control voltages and frequency within acceptable operating limits to accomplish the intended function of the plan. The intended function of the plan is outlined in R1 and includes transferring authority back to the BA. It would be unduly burdensome to perform dynamic simulations for each step in the process to get to this point. Also, it would be impossible to perform an actual test of the plan to this point since it would require creating a blackout to accomplish.

In the data retention section for R1, it is not clear what the change to 'monitoring activity' means. It previously clearly stated data must be kept since the last 'compliance audit'. 'Monitoring activity' is undefined and may include spot checks, audits, or any number of monitoring actions. The corresponding language in EOP-006-3 still says data must be kept since the last compliance audit. We recommend changing the language back to match EOP-006-3.

Likes 0	
Dislikes 0	

Response

Clay Young - SCANA - South Carolina Electric and Gas Co. - 3

Answer	No
Document Name	SCANA-SCEG Survey Responses.pdf
Comment	

Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, “at least once each 15 calendar months” it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

The revision to EOP-005 R8 adds the requirement R8.5 “Transition to Balancing Authority for Area Control Error and Automatic Generation Control.” We agree with the addition of this requirement and think required training in this area would be good for the industry. One possible concern with the proposed language has to do with when the TOP returns control of the BA Area back to the BA, the BA isn’t necessarily going back to Automatic Generation Control right away. Our suggestion would be to reword R8.5 to say, “Transition to Balancing Authority ensuring adequate Area Control Error (ACE) configuration and generation control”

Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance

Answer	No
Document Name	
Comment	

Under Project 2015-08, EOP-005-3 states that organizations will be required to obtain electronic confirmation/verification evidence (receipts) from entities when plans have been transmitted. This will be a challenge considering industry organizations have no control over the entities process once the plans have been received. LCRA is under the position to submit a negative vote with the proposed written revisions until further thought is given and changes are made to remove this requirement.

Likes 0	
Dislikes 0	
Response	

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1

Answer	No
Document Name	
Comment	

1. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, “at least once each 15 calendar months” it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

2. The revision to EOP-005 R8 adds the requirement R8.5 “Transition to Balancing Authority for Area Control Error and Automatic Generation Control.” We agree with the addition of this requirement and think required training in this area would be good for the industry. One possible concern with the proposed language has to do with when the TOP returns control of the BA Area back to the BA, the BA isn’t necessarily going back to Automatic Generation Control right away. Our suggestion would be to reword R8.5 to say, “Transition to Balancing Authority ensuring adequate Area Control Error (ACE) configuration and generation control”

Likes 0	
Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

A. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, “at least once each 15 calendar months” it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

B. The revision to EOP-005 R8 adds the requirement R8.5 “Transition to Balancing Authority for Area Control Error and Automatic Generation Control.” We agree with the addition of this requirement and think required training in this area would be good for the industry. One possible concern with the proposed language has to do with when the TOP returns control of the BA Area back to the BA, the BA isn’t necessarily going back to Automatic Generation Control right away. Our suggestion would be to reword R8.5 to say, “Transition to Balancing Authority ensuring adequate Area Control Error (ACE) configuration and generation control”

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Refer to #2 comments.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	No
Document Name	
Comment	
In the first sentence of Requirement R1 the proposed revision is to have the Requirement read that “Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator.” However, to be consistent with the language that is already being proposed for EOP-006-3 Requirement 1 the revision should read that each Transmission Operator “shall develop, maintain and implement” a restoration plan approved by its Reliability Coordinator. The wording proposed for EOP-006-3 should be used in EOP-005-3. Requirement R4 should be clarified to limit the type of System modifications that would require an update to the restoration plan solely to permanent System modifications that would change the Transmission Operator’s ability to implement its restoration plan. A definition of System modification should be added to the NERC Glossary. Or Instead of the expression “System Modifications” in R4, “BES modifications would be a better choice. The NERC Glossary definition of BES includes “Blackstart Resource” in its inclusion list. I3 – Blackstart Resources identified in the Transmission Operator’s restoration plan.	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	

In the first sentence of Requirement R1 the proposed revision is to have the Requirement read that “Each Transmission Owner shall develop and implement a restoration plan approved by its Reliability Coordinator.” However, to be consistent with the language that is already being proposed for EOP-006-3 Requirement 1 the revision should read that each Transmission Owner “shall develop, maintain and implement” a restoration plan approved by its Reliability Coordinator. The wording proposed for EOP-006-3 should be used in EOP-005-3.

Instead of the expression ‘System modifications” in R4, ‘BES modifications would be a better choice. The NERC Glossary definition of BES includes ‘Blackstart Resources’ in its Inclusion list

· I3 - Blackstart Resources identified in the Transmission Operator’s restoration plan.

Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CenterPoint Energy appreciates the SDT’s time and effort towards the improvement of the System Restoration from Blackstart Resources Standard and is generally amenable to the proposed revisions. CenterPoint Energy would like the SDT to consider the following changes to EOP-005-3. In R1, for consistency between the proposed EOP-005-3 and EOP-006-3 standards, CenterPoint Energy suggests the SDT align the proposed language in both R1s to be the same and use either, ”develop and implement”, or “develop, maintain, and implement”. Also, we are concerned that removal of the validation clause, “to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage” expands the scope of a restoration plan. We suggest the addition of language regarding the plan’s intended function of restoring the interconnecton and recommend the following: “The restoration plan shall accomplish its intended function allowing for restoration of the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service.” Without such additional language, a TOP could be expected to include in its retoration plan, steps to restore every Facility in its entire system. Furthermore, we support the retirement of R7, but believe that the language, “If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration” should be retained in the proposed R1. This language provides a TOP the flexibility to make adjustments to its restoration efforts based on Real-time System conditions and Facility availability regardless of contingency. Considering all of CenterPoint Energy’s comments R1 would state: “Each Transmission Operator shall develop, maintain, and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall accomplish its intended function allowing for restoration of the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of

Blackstart Resources is required to restore the shutdown area to service. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration. The restoration plan shall include:" In R4.2, to further clarify and to better align with the SDT's proposed changes in R2, we suggest the SDT replace, "No less than" with "At least" and also replace "implementation of" with "effective date of ". The requirement would then read, "R4.2. At least 30 calendar days prior to the Transmission Operator's effective date of the planned System modifications." CenterPoint Energy also believes that the proposed EOP-005-3 R8 (currently enforceable EOP-005-2 R10) along with its sub-requirements 8.1, 8.2, 8.3, 8.4, and 8.5 should be retired as they are inherent to the systematic approach to training processes. It is not that the requirements are duplicative, but rather that they are already incorporated in the training and periodicity of training that would be identified in a TOP's PER-005-2 analysis for company-specific reliability-related tasks. The criteria required to be included in the restoration plan outlined in R1.1 thru R1.9 further ensures that specific training content would be provided on system restoration and maps to the content being required in R8.1. R8.2, R8.3, R8.4, and R8.5. Retirement of R8 and its sub-requirements does not eliminate reliability-related task training on System Restoration from Black Start Resources. This rationale was applied in the recent revisions to PRC-001-1.2 (Project 2007-06.2) and industry approval of PER-006-1 to which training related requirements for the TOP were mapped out and retired. CenterPoint Energy urges the SDT to consider soliciting assistance and guidance from the PER-005 SDT and members from the training sector in the industry to assist in this matter.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

(1) R1 now includes "develop and implement" a restoration plan for the TOP. Measure M1 now calls out for evidence of implementation, including operator logs or voice recordings. This practice of including two actions, having a plan and implementing that plan, in a single requirement allows for additional scrutiny from an auditor. Our biggest concern is that R1 has nine sub-parts, which can now be reviewed under two filters – is it documented and does the entity have proof that they implemented it. We ask the SDT to consider modifying the requirement so evidence of implementation is separate from each of the nine sub-parts.

(2) We question the need for a change in R2 and R5 from "implementation date" to "effective date." They appear synonymous.

(3) We agree with the modification to R3 and R8 to remove the word "annually" and replace it with "at least once every 15 calendar months," as this aligns with several other NERC standards. We also agree with the removal of sub-part 3.1, as this was administrative in nature.

(4) Requirement R4 now requires the TOP to submit its restoration plan to the RC no more than 90 calendar days after identification of any unplanned system modification and no less than 30 calendar days prior to the TOP's implementation of planned system modifications. We question why the planned modifications were added to the requirement, as the TOP will be providing planned outages and other information to the RC already.

(5) Requirement R8 (formerly R10), added sub-part 8.5, which now includes the TOP to have training every 15 calendar months on the "transition to BA for ACE and AGC." We recommend modifying the phrase to "coordinate with the BA for restoration activities." The word "transition" could be misinterpreted that the TOP completely transfers their role to the BA in system restoration.

(6) Measure M10 (formerly M12), removed training records as proof of participation in restoration drills. Why was that type of evidence removed? It seems like the most straight-forward way to prove compliance with the requirement. Further, training records are still listed in M16 for GOP participation in restoration drills. This should be consistent throughout the standard.

Likes 0	

Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	

R1: For the purposes of managing internal controls, and clear internal controls ownership and tracking, consider keeping this requirement as Operations Planning horizon only and then do not remove R7 and R8. Plan development and administration is an Operations Planning function. Real Time is not responsible for development and maintenance of the plan.

R4.2. Is revised to state:

4.1.4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

This revision takes away flexibility. Suggest that "No less than 30 calendar days prior to" be changed to "Up to 90 calendar days after implementation of planned System modifications". Planned implementation dates are often moving targets and can move earlier or later, due to construction and crew scheduling needs, and well outside of the control of the plan administrators. If changes to the restoration plan were still in progress at the time of an event, System Operators would use restoration strategies in order to determine the best course of action.

Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	No
Document Name	FE 2015-08_EOP-005-3_IB_Comment_Form.docx
Comment	

Requirement R4: The proposed changes to R4 cause concern for FirstEnergy. The existing FERC approved requirement R4 requires notification by a Transmission Operator (TOP) to its Reliability Coordinator (RC) for a "permanent" system modification (planned or unplanned) "that would change the implementation of its restoration plan." The proposed revisions by the drafting team, while well intended, shifts the emphasis to changes that affect "ability to implement" the TOP restoration plan regardless of whether or not the system modification (planned or unplanned) is temporary or permanent. This change would cause numerous re-writes of restoration plans by TOPs and approval reviews by RCs resulting from planned maintenance outages of BES transmission facilities (lines, transformers, generators, etc.), many of which are short duration outages. FirstEnergy believes it is important to retain the "permanent" modification aspect of the existing FERC approved requirement. The proposed change results in an overly burdensome requirement without significant improvement to BES reliability.

FirstEnergy does support the intended 90-day notification for unplanned changes and the minimum 30-day lead-time from the effective date of planned changes.

FirstEnergy proposes the requirement be written as follows:

R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect permanent System modifications that would change the implementation of its restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications.

4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

A red-line version of our proposed changes is provide in the attached version of FE comments.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

We suggest the following edit to R1 for clarity:

"R1 Each Transmission Operator shall **develop** a restoration plan approved by its Reliability Coordinator. The **implemented** restoration plan shall allow…"

We believe this better aligns with the intent and doesn't create confusion that potentially an entity must have experienced a blackout in order to fully comply (a need to 'implement') with R1.

In R4 we request the re-insertion of the word 'permanent' into the requirement regarding the need to update the plan. Specifically the plan should be updated and re-submitted for approval upon ‘permanent’ System modifications. R4.1 and R4.2 should also get some additional language clarifying that the updates should only be made for ‘permanent’ system modifications. As stated, they require updates to be made for ‘any’ system modification no matter how small or impactful.

We have a concern that R6 in combination with the changes to R1 may seem to create a conflict or confusion. The changes to R1 seem to indicate the plan now covers restoration all the way up until balancing is turned over to the BA. That would seem to describe the ‘intended function’ of the plan as stated in R6. The sub-requirements in R6 seem to indicate simulation and analysis only needs to be done on energizing the Blackstart resource and connect initial loads. Perhaps R1.8 could be rephrased to better clarify the ‘intended function’ of the plan in order to better align with R6. We do not believe the intent is for dynamic simulation to be done for the entire restoration scenario all the way up to handoff to the BA in R1.9. Perhaps R6 could be rephrased such that it states:

R6 Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes **initial restoration**.

In the data retention section for R1, it is not clear what the change to ‘monitoring activity’ means. It previously clearly stated data must be kept since the last ‘compliance audit’. ‘Monitoring activity’ is undefined and may include spot checks, audits, or any number of monitoring actions. The corresponding language in EOP-006-3 still says data must be kept since the last compliance audit. We recommend changing the language back to match EOP-006-3.

Likes 0	
Dislikes 0	

Response

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC

Answer	No
Document Name	

Comment

Requirement R1: In the first sentence of Requirement R1, the proposed revision is to change the requirement that each Transmission Operator “shall have” a restoration plan approved by its Reliability Coordinator to state that each Transmission Operator “shall develop and implement” a restoration plan approved by its Reliability Coordinator. However, in order to be consistent with the language that is already been used in other requirements (see, e.g., the proposed revision in EOP-006-3, Requirement R1), the revision should state that each Transmission Operator “shall develop, maintain and implement” a restoration plan approved by its Reliability Coordinator. Accordingly, the ISO/RTO Council Standards Review Committee (SRC) suggests that the word “maintain” be added to the proposed revision. [CAISO does not support this paragraph.]

Requirement R4: The proposed revision in Requirement R4 requires the Transmission Operator to update and submit to its Reliability Coordinator for approval its restoration plan to reflect System modifications that would change the ability to implement its restoration plan. The requirement, however, should be clarified to indicate that the type of System monifications that would require an update to the restoration plan are only permanent System modifications that would change the Transmission Operator’s ability to implement its restoration plan. Limiting the requirement to reflect permanent modifications is consistent with the Rationale for Requirement R4, which states that the intent of the revisions is to require the Transmission Operator to update its restoration plan when major modifications need to be made, and not to require the Transmission Operator to make updates for minor revisions. Without the qualifying word “permanent,” the proposed revision could be read as requiring updates to the restoration plan for all System modifications that would change the Transmission Operator’s ability to implement the restoration plan, even if those System modifications are not permanent (such as for planned or unplanned outages). In the event that temporary System modifications or other unforeseen system conditions prevent the Transmission Operator from implementing the restoration plan as expected, system restoration would be facilitated by implementing the restoration strategies that Requirement R1 requires to be included in the restoration plan. System modifications that would change the Transmission Operator’s ability to implement the restoration plan that are not permanent are not “major.” Requiring that the restoration plan be updated for such nonpermanent System modifications would translate into multiple, unnecessary updates to the restoration plan. For this reason, to make the requirement even clearer, the SRC suggests that the word “permanent” (which is included in the currently enforceable version of this Requirement) be added to the proposed revision. Note that, for consistency, the word “permanent” should also be added in all the Violation Severity Levels for Requirement R4.

In addition, we suggest R 4.2. which currently states: “4.2. No less than 30 calendar days prior to the Transmission Operator’s implementation of planned System modifications” should be modified to state ”4.2. Up to 90 calendar days after implementation of planned System modifications.”

Planned implementation dates are often moving targets due to construction and crew scheduling needs. It is well outside the control of the plan administrators. If changes to the restoration plan were still in progress at the time of an event, System Operators would use restoration strategies in order to determine the best course of action. [NYISO does not support this comment.]

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2

Answer	No
Document Name	

Comment

The stricken phrase “to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator’s System.” should be retained. Since R1 is specifying that the TOP shall have an SRP to restore its system, it is imperative that the TOP has a defined state at which point it knows that it has successfully achieved the requirement. The stricken language provided that. Although R1.8 contains similar language, it is in the context of information that the TOP must include in its SRP, as opposed to defining success in achieving system restoration. Compliance with R1.8 does not inform the TOP, or an auditor, that if the TOP completes the processes contained in the subrequirement, that it has successfully achieved system restoration.

Likes 1	New York State Reliability Council, 10, ADAMSON ALAN
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6

Answer	No
Document Name	

Comment

Putting the word “implement” in EOP-005-3, R1: “Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator”, is confusing. What is meant by “implement”? Public Utility District of Chelan County (CHPD) understands “implement” to mean to put the

Restoration Plan into effect. The Restoration Plan is not put into effect until there is a real-time event.

CHPD would prefer the sentence to read: Each Transmission Operator shall develop a restoration plan and have it approved by its Reliability Coordinator.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	No
Document Name	

Comment

The proposed requirement R4.2 requires TOPs to submit revised System Restoration Plans “No less than 30 calendar days prior to the Transmission Operator’s implementation of planned System modifications.” This is not practical or advisable as it would result in the need for TOP’s to submit revised Restoration Procedures to the RC which do not align with actual system configuration during the (at least) 30 day period. Restoration plans are typically “approved” procedures that reflect current configuration and have a review and approval process internal to the TOP. Approval of revisions are closely coordinated with actual implementation of system modifications to ensure that proper configuration control is maintained between procedures and the system. Having to submit a revised (and approved) procedure at least 30 days in advance of field implementation would result in procedures having to be approved and sent to an RC that do not align with actual system configuration for “extended” periods (at least 30 days). Even if an effective date is used in a TOP’s procedural control process, having to assign such a date in excess of 30 days prior, would likely result in a significantly increased administrative burden due to the higher potential for date changes to occur between procedure approval and final implementation of a modification in the field. Field implementation of system modifications are subject to a degree of uncertainty due to a variety of factors (testing results, weather, system operational needs, etc). The greater the period of time between procedure revision approval and placement of a system modification in-service, increases the potential for subsequent procedure date changes being required and also raises the potential for non-alignment between Restoration Procedures and field configuration. Even if Draft Restoration Procedures are submitted to an RC, it is not clear that this would be satisfactory from a compliance standpoint for the TOP or the RC as proposed EOP-006-3 R5 requires the RC to approve a submitted TOP plan within 30 days of its receipt.

It is suggested that the proposed R4.2 be changed to delete “No less than 30 calendar days” and maintain the existing requirement to submit revised, planned, Restoration plans prior to their implementation.

Likes 0	
Dislikes 0	

Response

Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1

Answer	No
Document Name	

Comment

Portland General Electric Company (PGE) appreciates the efforts of the STD and being able to provide comments throughout this project. In the measure for R1 (M1) the term Disturbance is used, "…when a Disturance occurred…" Since not all Disturbances are Blackstart events, PGE suggests changing Disturbance to applicable event.

Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	No
Document Name	
Comment	

Compliance (Sec C.1)

We have concerns replacing "compliance audit" with "monitoring activity." The proposed term, "monitoring activity," is vague, ambiguous, and muddies the interpretation of the retention period. We can only speculate as to the reason for the change and, so, are unable to offer a suggestion to address our concern.

R2, R5, and R8

We are supportive of replacing "implementation date" with "effective date" and believe it provides added clarity.

We are supportive of replacing "annually" with "15 months" and believe it provides added clarity.

Likes 0	
Dislikes 0	
Response	

Jared Shakespeare - Peak Reliability - 1 - WECC

Answer	No
Document Name	
Comment	

For R3, Peak already has all the TOPs scheduled on an annual submittal process. Peak is concerned that TOPs will want to switch to a 15-month submittal process, which will be more difficult to track. Every approval will require an agreement on the next submittal scheduled rather than maintaining a known, 12-month schedule.

For R10, Can R16 be combined with R10? There are other requirements that combine various entities so not sure why participating in the RC's restoration plan would need to be separate requirements for TOPs and GOPs.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

The Purpose statement becomes an absolute positive by replacing “assure” with “ensure” therefore the restoration plan must reestablish reliability. System Operators need the flexibility to deviate from the plan in order to restore the system to precontingent operations.

Likes 0	
Dislikes 0	

Response

Jennifer Wright - Sempra - San Diego Gas and Electric - 1

Answer	No
Document Name	

Comment

In R1 we recommend that the first sentence be changed from “Each Transmission Operator shall develop and implement a restoration plan approved by its Relability Coordinator.”to “Each Transmission Operator shall develop and publish a restoration plan approved by its Relability Coordinator that will be implemented folwing a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down.” The reason for this recommendation is to clarify the intention of the proposed change.

In R1, we disagree with the change after the words “… is required to restore …”. Depending upon the cause of the Disturbance (for example physical damage) that requires system Restoration from Blackstart Resources, it may not be feasible to restore the entire shutdown area of service even though the BES has been restored. We recommend leaving the original wording in place.

In R4.2, we disagree with the wording “No less than 30 calendar days prior to …” in the first sentence. We recommend changing to “Up to 90 calendar days after implementation of planned System modifications”. The reason for this recommendation is that planned implementation dates are often moving targets due to factors such as construction or equipment delays; crew scheduling needs; or other factors outside the direct control of the entity.

Likes 0	
Dislikes 0	

Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	

We support NPCC's comments.

In addition, we have the following comments.

There is no reference to the formation of a BES island in EOP-005-3 Requirement R1 as there is in EOP-006-3 Requirement R1 (“or an energized island has been formed on the BES”). The Drafting Team should consider its inclusion in EOP-005-3 or its removal from EOP-006-3. However, we recommend inclusion rather than removal. Indeed, EOP-005 ‘s scope could be expanded to “System Restoration” regardless of whether Blackstart Resources are required or not. A TOP may have a major shutdown or be islanded and restore its area by synchronizing with an adjacent area. Such a TOP should nevertheless have a Restoration Plan, perform simulations as well as training. Such a change in scope would only require changes to the title and the purpose.

We note that R16 applies to Generator Operators, not Generator Operators identified in the Transmission Operators restoration plan, as was the case in EOP-005-2 R18. Most requirements in EOP-005-3 that apply to GOPs apply to GOPs with Blackstart Resources and these are identified in the TOP’s Plan. Modifying section 4.1.2. to apply only to GOP with Blackstart Resources would be consistent with EOP-006-3 R8 part 8.1 which specifies “each Generator Operator identified in the Transmission Operators’ restoration plans”. We recognize however that R16 is consistent with EOP-006-3 R8 in a general sense and also recall that in the development of EOP-005-2, comments on the same point were submitted and rejected by the drafting team at that time. If this project's drafting team rejects this comment again, **we request the addition of a rationale to clarify the purpose of this broader scope.** We note that the Régie de l'énergie here in Québec ordered a reduction of scope of R16 to the GOPs identified in the TOP plan, based on the lack of justification provided during the development of EOP-005-2 for the broader scope of R18 (now R16 in EOP-005-3).

R1: Suggest adding a rationale to explain change of scope. Does the removal of “the choice of the next Load to be restored is not driven by the need to control frequency or voltage” imply that the scope of the TOP’s restoration plan is now until all the BES is restored?

We understand that the EOP-005-3 Parts 1.9 and 8.5 that refer to transferring of Balancing Authority authority come from a FERC-NERC report. However, we believe that Balancing Authority functions always reside with the Balancing Authority. The requirement could be rephrased as a more general requirement to 'coordinate' the restoration with the appropriate BA, per RC criteria.

Likes 0	
Dislikes 0	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	No
Document Name	Comments on EOP 5.docx
Comment	

Likes 0	
Dislikes 0	
Response	
Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
For the sake of consistency I recommend considering on page 9 of 24 second line of M13 replacing the text "e-mail with" with "dated electronic". Similarly on page 10 of 24 third line of M14 the text "e-mail with" should be replaced with "dated electronic".	
Likes 0	
Dislikes 0	
Response	

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment

Regarding R8, Bonneville Power Administration (BPA) believes 15 months is too restrictive. BPA performs training semiannually (spring and fall). BPA requests the "not to exceed 15 months" to be changed to 18 months in order to allow any training that could not be accommodated in the previous semiannual training to be included in the subsequent period.

Regarding R4, BPA understands system modifications identified less than 30 days in advance to be emergency modifications and reportable within 90 days after the system modification. BPA desires clarifying language for system modifications identified less than 30 days in advance of the modification.

Regarding R8.5 and R1.9, BPA does not agree these to be necessary sub-requirements because the transition is non-critical. BPA as both a Transmission Operator and Balancing Authority does not perform a transition and believes these sub-requirements to be unnecessary or only applicable to Transmission Operators that are not also Balancing Authorities.

Likes 0	
Dislikes 0	

Response

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment

Regarding R8, Bonneville Power Administration (BPA) believes 15 months is too restrictive. BPA performs training semiannually (spring and fall). BPA requests the "not to exceed 15 months" to be changed to 18 months in order to allow any training that could not be accommodated in the previous semiannual training to be included in the subsequent period.

Regarding R4, BPA understands system modifications identified less than 30 days in advance to be emergency modifications and reportable within 90 days after the system modification. BPA desires clarifying language for system modifications identified less than 30 days in advance of the modification.

Regarding R8.5 and R1.9, BPA does not agree these to be necessary sub-requirements because the transition is non-critical. BPA as both a Transmission Operator and Balancing Authority does not perform a transition and believes these sub-requirements to be unnecessary or only applicable to Transmission Operators that are not also Balancing Authorities.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Yes. However, we think you should split R1 *develop* and R1.1 *implement functions*. ----Each Transmission Operator shall develop a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to allow for restoring the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service. The restoration plan shall include:

Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Yes. However, we think you should split R1 *develop* and R1.1 *implement functions*. ----Each Transmission Operator shall develop a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to allow for restoring the Transmission Operator’s System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service. The restoration plan shall include:{C}[JM(1]

{C}[JM(1]Bob H. addition

Likes 0	
Dislikes 0	
Response	

Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA

Answer	Yes
Document Name	
Comment	

FMPA generally agrees with the revisions proposed for EOP-005, but does have some comments.

R1 can still be interpreted that a TOP who would be restored via a tieline with a neighbor and not a Blackstart Resource does not need a restoration plan at all. What is the drafting team's intent here?

The phrasing of R4 needs work. FMPA recommends adding commas and removing the word "of".

"Each Transmission Operator shall update, and submit to its Reliability Coordinator for approval, its restoration plan to reflect System modifications that would change the ability to implement its restoration plan, as follows:"

R5 should use the defined term Control Center, rather than control room.

Likes 0	
Dislikes 0	

Response

Jeri Freimuth - APS - Arizona Public Service Co. - 3

Answer	Yes
Document Name	

Comment

In spirit APS is supportive of the SDT's direction. That said, APS offers the following suggested changes with respect to the proposed wording of the standard. APS suggests the following revised wording to further clarify the language in the proposed EOP-005 standard.

R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval its restoration plan to reflect System modifications that necessitate a change in how the Transmission Operator implements its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications; and

4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan available to its System Operators in its primary and backup control rooms in electronic or hardcopy format prior to its effective date in accordance with Requirement R5.

In addition, APS requests the SDT clarify the text for requirement R8.5 to align the requirement language with the text in the Rationale box for R8:

R8.5 Coordination needed to transfer the following functions back to the Balancing Authority: Area Control Error and Automatic Generation Control.

Likes 0	
Dislikes 0	

Response

Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	

GRU generally agrees with the revisions proposed for EOP-005, but does have some comments.

R1 can still be interpreted that a TOP who would be restored via a tieline with a neighbor and not a Blackstart Resource does not need a restoration plan at all. What is the drafting team's intent here?

The phrasing of R4 needs work. GRU recommends adding commas and removing the word "of".

"Each Transmission Operator shall update, and submit to its Reliability Coordinator for approval, its restoration plan to reflect System modifications that would change the ability to implement its restoration plan, as follows:"

R5 should use the defined term Control Center, rather than control room.

Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	

1. R4 Rationale: In the second paragraph the SDT may want to consider removing the word 'major' when describing System modifications as the requirement does not have this limitation, but instead deals with any System modifications that change the ability to implement the restoration plan. The use of the term 'minor' when describing revisions provides the appropriate context. Dominion also suggests the SDT could add examples into the Rationale to clarify the types of System modifications they are referring to.

1. Formatting observations compared to other NERC standard templates; The definition of CMEP under Section 1.1 should be at the top of Section 1 with the other definitions.

Section C. Compliance; The numbering in this section is incorrect. Section 1.1 should be the first definition and the numbering should follow from there for each distinct item.

Likes 0	
Dislikes 0	
Response	

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Document Name	
Comment	
Hydro One Networks Inc. would like to inquire from the drafting team on what an auditor would be required to view as evidence for measure M1 in the case that a Disturbance has not occurred over a given period in time?	
Likes 0	
Dislikes 0	
Response	

ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	

R1: Duke Energy recommends that the drafting team consider the following language revision to R1.

"Each Transmission Operator shall develop, maintain, and implement a restoration plan approved by its Reliability Coordinator."

We think that the addition of the term "maintain" is appropriate and would promote consistency with other EOP standards.

Also, we request clarification from the drafting team about the potential for an instance of double jeoparday. If an addition to the term "maintain" to R1 is deemed appropriate by the drafting team, does that open up entities to the possibility of violating two requirements if the restoration plan is not maintained. See Duke proposed R1 language, and SDT proposed language of R4. Does the failure to maintain a restoration plan create double jeopardy with R1 and R4?

R4: Duke Energy recommends the drafting team consider revising the proposed R4 to read as follows:

"Each Transmission Operator shall update and submit to its Reliabilty Coordinator for approval of its restoration plan to reflect system modifications, that

would inhibit its ability to implement its restoration plan, as follows:”

We feel that replacing the word “change” with “inhibit” or “adversely affect/negatively impact” is more accurate representation of what is needed in this requirement. Moreover, any planned or unplanned system modification could “change” the way an entity executes its restoration plan, but an entity would still be able to execute said plan via multiple paths. We feel that the spirit of this requirement should be geared more towards system modifications that prevent an entity from executing its restoration plan altogether.

R8: Duke Energy recommends that the drafting team consider maintaining the use of the annual system restoration training, rather than using *“at least once each 15 calendar months”.* We have a couple of concerns with the use of once each 15 calendar months. First, we are not aware that NERC has defined the term(s) calendar months. Some ambiguity may exist amongs industry stakeholders about what constitutes a calendar month. The use of the term “annual” is commonly used throughout the industry, and NERC has issued a Compliance Application Notice on the use of the term, and there seems to be more guidance on the tracking of annual timeframes.

R8.5: Duke Energy requests further clarification from the drafting team on how this requirement should apply to vertically integrated BA(s) and TOP(s) that are in the same control room. Also, with regards to the transition of ACE and AGC to the BA, where in the standard is it referenced when/if control was ever passed to the RC? Does this not go beyond what is outlined in R1.9? The language as written implies that a TOP was at one time in control of ACE or AGC. Not all entities may pass control over to the TOP, especially those entities that are vertically integrated, wherein the BA and TOP are in the same control room. We understand that this addition was a result of the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans, however, we don’t see this change as representative of the practices of the entire industry, and can’t agree with this addition based on the complication it may provide to vertically integrated companies.

Likes 0	
Dislikes 0	

Response

Mark Holman - PJM Interconnection, L.L.C. - 2

Answer	
Document Name	

Comment

PJM is concerned with the removal of the words in R1. In the proposed Standard, it is not clear when the use of the Restoration Plan should end. Adding the word “implement” to R1 and other requirements puts two actions in one requirement which makes the VSLs much more complicated. PJM has serious concerns with a misinterpretation of R6. The misinterpretation is that the entire Restoration Plan should be simulated using dynamics. That was not the intent of the SDT. Suggest adding “a combination of” before “steady state and dynamics simulations”. PJM would also recommend the addition of language clarifying that Dynamic simulation is only required from Blackstart unit to cranked unit (along the cranking path), and not the entire restoration plan. Also, PJM finds the “30 day prior to implementation” wording in R4.2 is troubling. This Requirement could potentially lead to artificial delays in energizing new equipment just to meet the 30 day requirement. PJM considers the wording in the current standard (“prior to a permanent planned modification”) sufficient, rather than introducing the 30 day prior requirement.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	
Comment	

Texas RE suggests Requirement R1 would be more clear if it was broken into two separate requirements: one Requirement to detail what a TOP's restoration plan should include and one Requirement for implementing the restoration plan and explaining when the plan should be implemented. As drafted, Requirement R1 does detail what the restoration plan should include, but it does not explicitly indicate when it should be implemented. This will promote consistency amongst the Standards as other Standards, such as PRC-005-6, have separate Requirements for having a plan/program and implementing the plan/program.

Texas RE is concerned EOP-005 has no requirement for TOPs to correct plans not approved by the RC. There appears to be issues if an RC does not approve the plan within 30 calendar of planned System modifications (or 90 days for unplanned). The modifications may be complete but the plan that includes the modifications may not be approved so an old copy (that cannot be utilized) will be in the Control Centers of a TOP. Texas RE recommends adding language regarding correcting unapproved plans as well as what a TOP is to do if an RC is late with its approval.

Texas RE is concerned about the proposed changes to EOP-005-2, Requirement R4. In particular, the SDT proposes to require TOPs to update and submit revised restoration plans to their RCs when there is modification "that would change the ability to implement" the restoration plan. Although Texas RE does not necessarily object to the SDT's stated intent to require updates solely for material changes, the requirement to update a plan should not hinge upon the entity's perception of its corresponding "ability" to implement the plan. That is to say, a material modification to the restoration plan should require submission of an updated plan regardless of whether the TOP believes the modification will or will not affect its ability to actually implement the existing restoration plan. This is particularly critical because EOP-005-3, Requirement R4 also serves the reliability goal of ensuring RCs have awareness regarding the steps TOPs will take in the restoration process. As such, even if a TOP believes it can still implement its current plan, providing information regarding material modifications to the restoration plan still serves the reliability goal of enhancing RC situations awareness.

If the SDT wishes to capture a materiality threshold for required updates and submissions, however, Texas RE recommends the SDT focus on the materiality of the change itself. Accordingly, the SDT could revise the proposed Requirement R4 language to simply require submission of an update "to reflect system modifications that would materially change the implementation of its restoration plan."

Likes 0	
Dislikes 0	
Response	

2. Do you agree with the retirements proposed in EOP-005-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	No
Document Name	
Comment	
Requirement 7 as it appears in EOP-005-2 is a better way to address the "implement" intent of EOP-005-3 R1.	
Likes 0	
Dislikes 0	
Response	

Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
R7 should be retained. It is imperative that a TOP have a fallback position in the event its SRP cannot be implemented as intended. R7 specifies to the TOP that the fall back position is to utilize its strategy. For example, a TOP's SRP might have detailed steps to restore a certain generating unit, perhaps by specifying a particular switching scheme. If the facilities to execute that scheme are not available, the TOP should still recognize the need to restore that unit, and proceed in any manner available to do so. The strategy is to restore the unit regardless of the tactics used to accomplish that. R1.1 does obligate a TOP to include it strategies in its SRP, but it does not obligate it to operate to those strategies if need be. Further, the strategies in a TOP SRP are at a more detailed level than the strategy of the RC plan in EOP-006. An RC's plan is, in effect, it's strategy, and is at a much higher and more general level than the TOP plan. Therefore, there is no inconsistency with retaining R7 in EOP-005 and removing it from EOP-006. R8 should be retired.	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	

Please see comment in response to Q1 above.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
It is the responsibility of the TOP to notify the RC before resynchronization with neighbors, Southern believes that without specifically being addressed in a standard that some TOPs may not be compeled to consult with the RC before restoring tie-lines creates a potential reliability gap. Comment for EOP-005-3 R4.1: No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications that would affect implementing the restoration plan. Comment for EOP-005-3 R4.2: No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications that would affect implementing the restoration plan.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement. Maybe add subpart to R1 to clarify RC approval of re-synchronization of islands if R8 is removed.	
Likes 0	
Dislikes 0	
Response	

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	
Comment	

Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement.

Maybe add subpart to R1 to clarify RC approval of re-synchronization of islands if R8 is removed.

Likes 0	
Dislikes 0	
Response	

Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Document Name	
Comment	

Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement.

Maybe add subpart to R1 to clarify RC approval of re-synchronization of islands if R8 is removed.

Likes 0	
Dislikes 0	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	

If the draft R1 is modified to remove “implement”, which we agree it should be, then R7 needs to stay. Changing R1 and removing R7 will result in a requirement to have a plan but no requirement to actually use the plan when needed. We agree that R8 is not needed since the RC plan required in

EOP-006 is required to have criteria for re-establishing interconnections and the TOP plan is required to follow the RC plan (EOP-005 R1.1).

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

If the draft R1 is modified to remove “implement”, which we agree it should be, then R7 needs to stay. Changing R1 and removing R7 will result in a requirement to have a plan but no requirement to actually use the plan when needed. We agree that R8 is not needed since the RC plan required in EOP-006 is required to have criteria for re-establishing interconnections and the TOP plan is required to follow the RC plan (EOP-005 R1.1).

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

If the draft R1 is modified to remove “implement”, which we agree it should be, then R7 needs to stay. Changing R1 and removing R7 will result in a requirement to have a plan but no requirement to actually use the plan when needed. We agree that R8 is not needed since the RC plan required in EOP-006 is required to have criteria for re-establishing interconnections and the TOP plan is required to follow the RC plan (EOP-005 R1.1).

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment	
If the draft R1 is modified to remove “implement”, which we agree it should be, then R7 needs to stay. Changing R1 and removing R7 will result in a requirement to have a plan but no requirement to actually use the plan when needed. We agree that R8 is not needed since the RC plan required in EOP-006 is required to have criteria for re-establishing interconnections and the TOP plan is required to follow the RC plan (EOP-005 R1.1).	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Resynchronizing areas is a sensitive piece of system restoration. Much work has to go into getting systems ready for resynchronization and without proper coordination, a misstep could put all of that load in jeopardy of being dropped. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement.	
Likes 0	
Dislikes 0	
Response	
Tina Garvey - Austin Energy - 4	
Answer	No
Document Name	
Comment	
I support the comments of Andrew Gallo.	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	No

Document Name	
Comment	

Unless the changes AE recommends above are implemented, R7 should not be deleted in its entirety. (See AE's response to Question 1, above) Because of the vagaries of a blackstart situation, AE believes the Standard should allow the Transmission Operator to solve issues which may not be addressed in the restoration plan. AE believes it is not possible to plan for every possible contingency and, therefore, Transmission Operators need a degree of freedom to address deviations from expectations. Therefore, AE requests the sentence "If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration" remain unless included in R1 as suggested above.

Likes 0	
Dislikes 0	
Response	

Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF

Answer	No
Document Name	
Comment	

R7: . Implementation documentation should remain covered under the current Requirement 7. Focus should be on developing a restoration plan in Requirement 1 and Measurement 1 should not be confused with implementation documentation. Revise the existing R7 requirement for implementation and measures for implementation as needed.

R8. Recommend retaining or at least retaining "in accordance with the established procedures of the Reliability Coordinator". Much work has been done in this venue to provide needed guidance, and see this as an efficient way to accomplish. The Reliability Coordinator must play a defined role when establishing ties. It's the RC's role to ensure each Transmission Operator's System is ready for the connection.

Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
We support NPCC's comments.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Reword R8.5 “Transition to Balancing Authority for Area Control Error and Automatic Generation Control” needs to clearly state that a hand off of responsibilities are necessary at the end of system restoration.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
We are supportive of the retirements proposed in EOP-005-3 of R7 and R8.	
Likes 0	
Dislikes 0	
Response	

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Yes, given that Requirement R1 is being revised to state that the Transmission Operator shall "implement" a restoration plan approved by its Reliability Coordinator, Requirements R7 and R8 can, and should, be retired. [CAISO and NYISO do not support this comment]	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
We understand the rationale behind the changes.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
We agree with the proposed retirements of R7 and R8.	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	Yes
Document Name	
Comment	
See comment to Question 1 proposing to retain the use of the language, “If the restoration plan cannot be executed as expected the Transmission Operator shall utilize its restoration strategies to facilitate restoration”.	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
What is the SDT’s thought process in removing the need for the Transmission Operator to obtain authorization of the Reliability Coordinator prior to resynchronizing its area with that of a neighboring Transmission Operator’s area under requirement R8?	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	

Answer	Yes
Document Name	
Comment	

Assuming that Requirement R1 is being revised to state that the Transmission Owner shall “implement” a restoration plan approved by its Reliability Coordinator, Requirements R7 and R8 should be retired.

Likes 0	
Dislikes 0	
Response	

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	
Comment	

Regarding R8, Bonneville Power Administration (BPA) believes 15 months is too restrictive. BPA performs training semiannually (spring and fall). BPA requests the "not to exceed 15 months" to be changed to 18 months in order to allow any training that could not be accommodated in the previous semiannual training to be included in the subsequent period.

Regarding R8.5 and R1.9, BPA does not agree these to be necessary sub-requirements because the transition is non-critical. BPA as both a Transmission Operator and Balancing Authority does not perform a transition and believes these sub-requirements to be unnecessary or only applicable to Transmission Operators that are not also Balancing Authorities.

Likes 0	
Dislikes 0	
Response	

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	
Comment	

Regarding R8, Bonneville Power Administration (BPA) believes 15 months is too restrictive. BPA performs training semiannually (spring and fall). BPA requests the "not to exceed 15 months" to be changed to 18 months in order to allow any training that could not be accommodated in the previous semiannual training to be included in the subsequent period.

Regarding R8.5 and R1.9, BPA does not agree these to be necessary sub-requirements because the transition is non-critical. BPA as both a Transmission Operator and Balancing Authority does not perform a transition and believes these sub-requirements to be unnecessary or only applicable

to Transmission Operators that are not also Balancing Authorities.

Likes 0	
Dislikes 0	

Response

Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
I agree with the changes however, training requred by R8.5 makes no sense if a TOP does not manage Area Control Error and/or Automatic Generation Control. My utility is a small TOP and has neither ACE management or AGC management. Training in the transition of this functionality to the BA is unnecessary since the BA provides this funcionality as part of its normal operations.	
Likes 0	
Dislikes 0	
Response	

Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

No.

Texas RE does not necessarily object to the SDT's proposal to retire Requirements R7 and R8 from the EOP-005-3 Standard. However, Texas RE is concerned that several substantive elements of those Requirements are not explicitly incorporated into the proposed EOP-005-3 R1 restoration plan implementation requirements. Texas RE has identified two principal areas of concern, and suggests the SDT revise in proposed language in R1 to address these issues.

First, Requirement R7 provides not only that each affected Transmission Operator (TOP) shall implement its restoration plan following a Disturbance, but also that if "the restoration plan cannot be executed as expected the [TOP] shall utilize its restoration strategies to facilitate restoration." As presently drafted, there is no explicit requirement in the revised Requirement R1 requiring TOPs to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed. This adaptive capability serves an important function and promotes TOPs continuing to maintain situational awareness and strategic reactions throughout the course of restoration activities. As such, Texas RE recommends that if the SDT wishes to retire Requirement R7, it include the following language in the restoration plan content requirements specified in Requirement R1 in order to address this issue:

1.10 Strategies to facilitate restoration if the other elements of the restoration plan cannot be executed as expected.

Second, Requirement R8 presently provides an explicit requirement that TOPs "resynchronize area(s) with neighboring [TOPs] only with the authorization of the Reliability Coordinator or in accordance with established procedures of the Reliability Coordinator." Although it is perhaps possible to read R1.1's mandate that the restoration plan include "[s]trategies for system restoration that are coordinated with the [RC's] high level strategy for restoring the interconnection" as encompassing this requirement, it is not clear that resynchronization is included within either "system restoration strategies" or the RC's "high level strategy." Moreover, there is no explicit reference to coordination activities with neighboring TOPs elsewhere in the Standard. To clarify this issue and ensure coordination activities are adequately addressed in entity restoration plans, Texas RE recommends that if the SDT wishes to retire R8, it include the following language in the restoration plan content requirements specified in R1 to address this issues:

1.11 Procedures to resynchronize area(s) with neighboring Transmission Operator area(s) after obtaining authorization from the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator.

Texas Re noticed draft EOP-005-3 does not follow the results based standards template. On the template, Section C 1.1 is the Compliance

Enforcement Authority. Section C 1.2 Is the Evidence Retention. Section C 1.3 Is the Compliance Monitoring and Enforcement Program. There is no section for Reset Time Frame, Compliance Monitoring and Enforcement Processes, or Additional Compliance Information.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

It is hard to be compliant to R1 without R7. We suggest you adjust the language in R1 or keep R7.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

It is hard to be compliant to R1 without R7. We suggest you adjust the language in R1 or keep R7.

Likes 0	
Dislikes 0	

Response

3. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
The word “neighboring” should be replaced with the word “electrically adjacent” in all instances in the standard (including the Violation Severity Levels). “Electrically adjacent” lends more clarity to the intent of the requirements than “neighboring.” It is suggested that the below changes be made to Part 4.1 so that it reads: “If a Reliability Coordinator finds conflicts between its restoration plan and the restoration plan of an electrically adjacent Reliability Coordinator, the Reliability Coordinator and the adjacent Reliability Coordinator shall resolve the conflicts within 30 calendar-days of written notification of the identified conflicts from the Reliability Coordinator to the adjacent Reliability Coordinator.” The additional revisions clarify that both the initiating Reliability Coordinator, and the electrically adjacent Reliability Coordinator have to resolve any conflicts. The timing for resolution of the conflicts will also be made clear.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Consider revising R3 to allow "Annual" review to be consistent with other NERC standards. The verbiage change from "Annual" to "at least every 15 months" in R7 is unnecessary and does not improve the standard. Additionally, it is not consistent with numerous other standards that currently contain "Annual" requirements.	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	

Answer	No
Document Name	
Comment	

The language to "implement" the system restoration plan has the potential to create confusion within the industry. Implementation of the a restoration plan would require a system outage to be compliant. Language should be adjusted to represent the intent of the SDT.

Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	
Comment	

ERCOT joins with the comments of the IRC Standards Review Committee (SRC). ERCOT also offers this additional point:

Similar to the comment for Question #1, we ask that a conditional phrase be added to the language of Requirement R1 to clarify that the restoration plan will only be implemented during an actual blackstart event. Otherwise, the requirement as written indicates that the entity must have implemented a restoration plan absent an event. As such, we recommend language that clarifies this: “Each Reliability Coordinator shall develop, maintain, and, in the event of a Disturbance, implement a Reliability Coordinator Area restoration plan.”

If the SDT intends there to be a difference in meanings of the words “adjacent” and “neighboring,” we request that this difference be explained and made more explicit in the language of the standard.

We also ask for clarification on the meaning of the phrases “adjacent Transmission Operators” and “adjacent Reliability Coordinators,” for the ERCOT interconnection, as neither of these terms is defined. We ask the SDT to clarify that, consistent with the interpretation of Question 2 in Appendix 1 to EOP-001-2.1b, “adjacent” should not be read to apply to RCs or TOPs that are not “within the same Interconnection.” This change is appropriate because ERCOT does not rely on SPP or MISO for system restoration, and SPP and MISO also do not rely on ERCOT for that purpose.

Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	
Comment	

Most training is conducted on a yearly basis, with certain required training every year. For example, TVA has three cycle training classes lasting seven weeks each cycle in order to get all of the operators through the training. At times it makes more sense to conduct specific required training in one cycle versus another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if the System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training was required "once per calendar year." That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around from year to year as needed.

EOP-006-3 R1 states, "Each Reliability Coordinator shall develop, maintain, and implement" while EOP-005-5 R1 states, "Each Transmission Operator shall develop and implement." We recommend that the "develop and implement" language in EOP-005-3 R1 be used in EOP-006-3 R1 for consistency among the two standards.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

R7: See Duke Energy's comment regarding the replacement of "annual" with "at least once each 15 calendar months" in response to question 1 above.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements and similar to EOP-005. R1 should require a plan and define what needs to be in the plan. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan. The corresponding proposed measures would need to be modified accordingly.

We believe the wording of R8.1 is problematic and that the intent is that those that have a role in an RC drill, exercise, or simulation participate in those activities. We believe that it is better to require that the RC notify all entities that have a role in each RC drill, exercise or simulation. The identified entities should be required to participate in each activity for which they have a role. We suggest rewriting R8.1 as:

R8.1 Each Reliability Coordinator shall request each enitity which has a role in the RC drill, exercise or simulation participate in those drills, exercises, or simulations.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements and similar to EOP-005. R1 should require a plan and define what needs to be in the plan. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan. The corresponding proposed measures would need to be modified accordingly.

We believe the wording of R8.1 is problematic and that the intent is that those that have a role in an RC drill, exercise, or simulation participate in those activities. We believe that it is better to require that the RC notify all entities that have a role in each RC drill, exercise or simulation. The identified entities should be required to participate in each activity for which they have a role. We suggest rewriting R8.1 as:

R8.1 Each Reliability Coordinator shall request each enitity which has a role in the RC drill, exercise or simulation participate in those drills, exercises, or simulations.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements and similar to EOP-005. R1 should require a plan and define what needs to be in the plan. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan. The corresponding proposed measures would need to be modified accordingly.

We believe the wording of R8.1 is problematic and that the intent is that those that have a role in an RC drill, exercise, or simulation participate in those activities. We believe that it is better to require that the RC notify all entities that have a role in each RC drill, exercise or simulation. The identified entities should be required to participate in each activity for which they have a role. We suggest rewriting R8.1 as:

R8.1 Each Reliability Coordinator shall request each enitity which has a role in the RC drill, exercise or simulation participate in those drills, exercises, or simulations.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

We agree with the concept of requiring a plan, maintainance of the plan, and implementation of the plan. However, we believe these should be separate requirements and similar to EOP-005. R1 should require a plan and define what needs to be in the plan. R7 should be retained to require implementation of the plan. Other requirements already address maintaining the plan. The corresponding proposed measures would need to be modified accordingly.

We believe the wording of R8.1 is problematic and that the intent is that those that have a role in an RC drill, exercise, or simulation participate in those activities. We believe that it is better to require that the RC notify all entities that have a role in each RC drill, exercise or simulation. The identified entities should be required to participate in each activity for which they have a role. We suggest rewriting R8.1 as:

R8.1 Each Reliability Coordinator shall request each enitity which has a role in the RC drill, exercise or simulation participate in those drills, exercises, or simulations.

Likes 0	
Dislikes 0	

Response	
Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Document Name	
Comment	

Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

EOP-006-3 R1 states: Each Reliability Coordinator shall develop, *maintain*, and implement.

EOP-005-5 R1 states: Each Transmission Operator shall have develop and implement.

We recommend 'develop and implement' language in EOP-005-3 R1 be used in EOP-006-3 R1 also for consistency among the two standards.

Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	
Comment	

1. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.
2. EOP-006-3 R1 states: Each Reliability Coordinator shall develop, *maintain*, and implement. EOP-005-5 R1 states: Each Transmission Operator shall have develop and implement. We recommend 'develop and implement' language in EOP-005-3 R1 be used in EOP-006-3 R1 also for consistency among the two standards.

Likes 0	
Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

A. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, “at least once each 15 calendar months” it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

B. EOP-006-3 R1 states: Each Reliability Coordinator shall develop, *maintain*, and implement..EOP-005-5 R1 states: Each Transmission Operator shall have develop and implement. We recommend ‘develop and implement’ language in EOP-005-3 R1 be used in EOP-006-3 R1 also for consistency among the two standards.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Requirement 8 should NOT be retired. It is a critical step in the Restoration Plan that requires RC approval.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No

Document Name	
Comment	

(1) R1 now includes “develop, maintain, and implement” a restoration plan for the RC. We question why “maintain” was included in EOP-006-3, but it only states “develop and implement” for the TOP in EOP-005-3. This is inconsistent language and should be aligned.

(2) We disagree with the inclusion of “maintain and implement.” Measure M1 now calls out for evidence of implementation, including operator logs or voice recordings. This practice of including three actions, having a plan, maintaining the plan, and implementing that plan, in a single requirement allows for additional scrutiny from an auditor. Our biggest concern is that R1 has six sub-parts, which can now be reviewed under three filters – is it documented, is it maintained, and does the entity have proof that they implemented it. We ask the SDT to consider modifying the requirement so evidence of implementation is separate from each of the six sub-parts.

(3) For R3, we agree with the change from 13 calendar months to 15 calendar months to align with other NERC standards.

(4) For R7 (formerly R9), we agree with changing annual to 15 calendar months to align with other NERC standards.

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	No
Document Name	

Comment

Please see our response to Q1 regarding R1 of EOP-005-3 which we feel are applicable to EOP-006-2 as well.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

It seems that there was inconsistent use of ‘maintain’ in R1 between EOP-006-3 and EOP-005-3. We suggest removing the word ‘maintain’ in R1 since it is redundant with requirement R3. Also M1 would need to be edited to measure that the plan was appropriatel ‘maintained’ as well as implemented. As stated, it does not verify that the plan was maintained.

In the revised R1.2 we just point out that there can be ‘adjacent’ entities that may not be within the same Interconnection (example: SPP BA/RC and

ERCOT BA/RC) that it may not be appropriate or necessary to coordinate restoration plans. One way to handle this may be to specify that coordination must be performed with entities within the same Interconnection, or alternatively allow the restoration plan to dictate which entities are considered adjacent.

We believe the intent of the proposed R8.1 is to only require participation by TOPs and GOP's who 'have a role' in the restoration plan. There are TOPs and GOP's in the RC Area who may never have a role in restoration activities (aka wind farms or small TOPs). We suggest rewriting R8.1 as:

R8.1 Each Reliability Coordinator shall request each Transmission Operator **which has a role** in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least **once** every two calendar years.

Likes 0	
Dislikes 0	

Response

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC

Answer	No
Document Name	

Comment

In Requirement R1.2, the proposed revisions establish that the restoration plan must include criteria and conditions for re-establishing interconnections with other Transmission Operators within the Reliability Coordinator's Area, with "adjacent" Transmission Operators in other Reliability Coordinator Areas, and with "adjacent" Reliability Coordinators. The use of the word "adjacent" is more appropriate as it makes the requirement more clear. The SRC suggests a further clarification that is consistent with the interpretation of Question 2 in Appendix 1 to EOP-001-2.1b, which states that "adjacent" should not be read to apply to RCs or TOPs that are not "within the same Interconnection." The SRC suggests that the words "electrically adjacent" be used throughout the standard. Specifically, the word "neighboring" should be replaced with the word "electrically adjacent" in all instances in the standard (including the Violation Severity Levels), because "electrically adjacent" is clearer than "neighboring"or "adjacent" (alone).

In addition, the SRC suggests that clarifying changes be made in Requirement 4, Part 4.1, so that it reads as follows:

4.1. If a Reliability Coordinator finds conflicts between its restoration plans and the restoration plans of an adjacent Reliability Coordinator, the Reliability Coordinator and the adjacent Reliability Coordinator shall resolve the conflicts within 30 calendar days of written notification from the Reliability Coordinator to the adjacent Reliability Coordinator of the identified conflicts.

The additional revisions make clear that both the Reliability Coordinator and the adjacent Reliability Coordinator have to resolve any conflicts, and the timing for resolution will also be clear.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
see comments from IRC/SRC	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE suggests Requirement R1 would be more clear if it was broken into two separate requirements: one Requirement to detail what a RC's restoration plan should include and one Requirement for implementing the restoration plan and explaining when the plan should be implemented. As drafted, Requirement R1 does detail what the restoration plan should include, but it does not explicitly indicate when it should be implemented. This will promote consistency amongst the Standards as other Standards, such as PRC-005-6, have separate Requirements for having a plan/program and implementing the plan/program.

Texas RE recommends clarifying the Reliability Coordinator's obligations to "maintain" a restoration plan. As currently drafted, neither the measure nor VSLs specifies the evidence or severity of an issue associated with the failure to maintain. One possible interpretation of this requirement is that RC's must use the proposed 15 month reviews to ensure their plan includes appropriate criteria and processes for the re-energization of shutdown areas. However, it possible that RCs may have additional or distinct obligations. Texas RE requests that the SDT provide additional information regarding maintenance obligations under this requirement.

Texas RE recommends defining the terms "neighboring" and "adjacent". It is unclear whether or not there is a difference in what those terms mean. Requirement R1 has "neighboring" RC reference but Requirement part 1.2 has "adjacent" referenced. In 4.1 "neighbors" is used (and is assumed to RCs). There appears to not be a requirement to provide the RC plan to neighboring/adjacent TOPs There should be consistency in terms used and it should be well understood by all RCs that adjacent/neighboring is the RC (or RCs) that is (are) touched at the boundary regardless of synchronous or asynchronous connectivity.

Texas RE is concerned that, without parts 1.2,1.3, and 1.4, there may not be clarity provided in roles and responsibilities within a restoration plan. There should be Operating Processes utilized by the RC. The restoration plan should clearly indicate coordination efforts with TOPs and RCs. In the proposed 1.2 (old 1.5) there is a reference to "adjacent" TOPs in other RC Areas but no requirement to provide the RC restoration plan to those adjacent TOPs (nor a requirement for the adjacent RC to provide the plan). This appears to be a gap in reliability if there are criteria for "reestablishing interconnections" with TOPs in other RC Areas. It is unclear whose role or responsibility it is that to provide the information.

Texas Re noticed draft EOP-006-2 does not follow the results based standards template. On the template, Section C 1.1 is the Compliance Enforcement Authority. Section C 1.2 Is the Evidence Retention. Section C 1.3 Is the Compliance Monitoring and Enforcement Program. In the EOP-006-2 draft, compliance Enforcement Authority does not have a section. The reset Time Frame and Evidence retention is section C 1.1. C1.2 is Compliance Monitoring and Enforcement Processes Program (incorrect section and title)

Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Document Name	
Comment	

There are multiple references to "neighboring RCs" in the Standard. Can these all be replaced, as appropriate, with the word "adjacent RCs?" If the intent as referenced with the change in R1.2 holds true to the whole Standard then clarifying neighbors to be "direct connection" instead of "just neighbors without electrical adjacency." This is particularly true for R4 – is it really necessary for Peak to review MISO's Restoration plan now that we have no electrical connection with them?

Old R10.1 (new R8.1): Peak seeks clarification – shouldn't the new R8.1 follow the same logic of 15 months instead of 24 months so as to keep it in line with new R7 (internal restoration drill training)? Or is the intent that every 15 months RCs train internally but only every 24 months they invite all TOPs and GOPs?

Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	

We support NPCC's comments.

In addition, we have the following comments.

M4 does not reflect the written notification time requirement (60 days) in R4. We suggest :

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans, **has provided written notification of any conflicts within 60 calendar days** and resolved any conflicts within 30 calendar days of notification in accordance with Requirement R4.

The VSL table for R4 does not address situations where the RC reviews the submitted plans but does not provide written notification of a conflict. (in those situations, the timer for the resolution of conflicts between the plans never starts.)

We note that requirements 1 and 2 refer to the 'RC Area restoration plan' whereas the rest of the requirements skip 'Area'.

Likes 0	
Dislikes 0	
Response	
Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
FMPA generally agrees with the revisions proposed for EOP-005, but has one comment. R6 should use the defined term Control Center, rather than control room.	

Likes 0	
Dislikes 0	
Response	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	

GRU generally agrees with the revisions proposed for EOP-005, but has one comment. R6 should use the defined term Control Center, rather than control room.

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	

1. For additional clarification, Dominion suggests the following changes to R4; Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered between restoration plans during that review within 60 calendar days of receipt.
2. In Part 4.1, Dominion suggests the following change to clarify when the 30 day period starts:

If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of delivery of written notification.

1. Formatting observations compared to other NERC standard templates; The definition of CMEP under Section 1.1 should be at the top of Section 1 with the other definitions.

Section C. Compliance: The numbering in this section is incorrect. Section 1.1 should be the first definition and the numbering should follow from there for each distinct item.

Likes 0	
Dislikes 0	
Response	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy believes that for consistency between the EOP-005-3 and EOP-006-3 proposed standards the language proposed in both R1s should be consistent and use either, "develop and implement", or "develop, maintain, and implement".	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Andrew Gallo - Austin Energy - 6

Answer	
Document Name	

Comment

EOP-006-3 does not apply to AE and, therefore, we have no opinion.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	
Document Name	

Comment

No Opinion.

Likes 0	

Dislikes 0	

Response

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane

Answer	
Document Name	

Comment

This standard is not applicable to Hydro One Networks Inc.

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6

Answer	
Document Name	

Comment

EOP-006-2 is applicable to Reliability Coordinators only. CHPD is not registered as a Reliability Coordinator. As such, CHPD does not have an opinion.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	
Document Name	

Comment

RC only.

Likes 0	
Dislikes 0	

Response	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	
Document Name	
Comment	
Only applicable to the RC; SDG&E has no comments.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the retirements proposed in EOP-006-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
R7 requires at least once each 15 calendar months, annual System restoration training for its System Operators. R8 requires two System restoration drills, exercises, or simulations per calendar year. Need to assure that System Operators attend at least one of two annual drills, exercises or simulations every 15 months. The intent is that all entities within the restoration plan are adequately trained and aware of the attributes of the restoration plan.	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	
Please see comments above which apply to EOP-006 as well.	
Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The Violation Severity Level should match the proposed Standard EOP-006-3 Requirement R8 instead of Requirement R8.1.	
Likes 0	
Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Lack of coordination could have a large impact on system reliability during system restoration. The requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on "The coordination role of the Reliability Coordinator and Reestablishing the Interconnection". It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization of with neighboring TOPs and RCs.	
Likes 0	
Dislikes 0	
Response	

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	
Comment	
1. One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Lack of coordination could have a large impact on system reliability during system restoration. The requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on "The coordination role of the Reliability Coordinator and Reestablishing the Interconnection". It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization of with neighboring TOPs and RCs.	
Likes 0	
Dislikes 0	
Response	

Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No

Document Name	
Comment	

One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Lack of coordination could have a large impact on system reliability during system restoration. The requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on “The coordination role of the Reliability Coordinator and Reestablishing the Interconnection”. It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization of with neighboring TOPs and RCs.

Likes 0	
Dislikes 0	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	
Comment	

See comments to #2

Likes 0	
Dislikes 0	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	
Comment	

See comments to #2

Likes 0	
Dislikes 0	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	
See comments to #2	
Likes 0	
Dislikes 0	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	
See comments to #2	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
Resynchronizing areas is a sensitive piece of system restoration. Much work has to go into getting systems ready for resynchronization and without proper coordination, a misstep could put all of that load in jeopardy of being dropped. One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Because lack of coordination could have such a large impact on system reliability during system restoration, the requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on “The coordination role of the Reliability Coordinator and Reestablishing the Interconnection”. It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization with neighboring TOPs and RCs.	
Likes 0	

Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	No
Document Name	
Comment	
See answer to Number 2.	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	No
Document Name	
Comment	
R7 requires System Operator training every 15 months and R8 requires two drills, exercises or simulations every calendar year. The NSRF requests that R7 and R8 be combined to to assure that System Operators attend at least one of two annual drills, exercises or simulations every 15 months. The SDT can add in the sub-Requirements to capture all concerned parties. The intent is that all entities within the restoration plan are adequately trained and aware of the attributes of the restoration plan.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
We support NPCC's comments.	
Likes 0	

Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	Yes
Document Name	

Comment

We are supportive of the retirements proposed in EOP-006-3 of R7 and R8.

Likes 0	
Dislikes 0	

Response

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC

Answer	Yes
Document Name	

Comment

Yes, given that Requirement R1 is being revised to state that the Transmission Operator shall “implement” a Reliability Coordinator Area restoration plan, Requirements R7 and R8 can, and should, be retired. [CAISO and SPP do not support this comment.]

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

We agree with the proposed retirement of R7 and R8.

Likes 0	

Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
1. New M7: Remove the additional 'M7', that is listed above R7 2. New M8: The request to participate is applicable to part 8.1 only in the last sentence, therefore Dominion suggests the last sentence in M8 be written to read as; And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate per Requirement 8 Part 8.1.	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Assuming that Requirement R1 is being revised to state that the Reliability Coordinator shall "implement" a Reliability Coordinator restoration plan, Requirements R7 and R8 should be retired.	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes

Document Name	
Comment	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	
Document Name	
Comment	
Only applicable to the RC; SDG&E has no comments.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Consistent with the comments in response to Question 2 above on EOP-005, Texas RE is concerned that several substantive elements of those Requirements are not explicitly incorporated into the proposed EOP-006-3 Requirement R1 restoration plan implementation requirements. Specifically, Requirement R7 provides not only that each affected RC shall implement its restoration plan following a Disturbance, but also that if "the restoration plan cannot be executed as expected the [RC] shall utilize its restoration strategies to facilitate restoration." As Texas RE indicated above, there is no explicit requirement in the revised EOP-006-3, Requirement R1 requiring RCs to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed. Although important for TOPs, these forms of adaptive strategies are particularly critical for RCs given their wide-area view of the BES and overall role in coordinating effective responses to Disturbances. As such, Texas RE recommends incorporating the following language into EOP-006-3, Requirement R1 if the SDT concludes the full retirement of EOP-006-3, Requirement R7 is appropriate:

1.7 Strategies to facilitate restoration if the other elements of the restoration plan cannot be executed as expected.

In a similar vein, EOP-006-3, Requirement R8 presently requires the RC to "coordinate and authorize resynchronizing islanded areas that bridge boundaries between [TOPs] or [RCs]. If the resynchronization cannot be completed as expected the [RC] shall utilize its restoration plan strategies to facilitate resynchronization." Similar to EOP-005-3, Requirement R1, these elements of R8 are not explicitly included within the various required parts of the RC's restoration plan as specified in EOP-006-3, R1.1 to 1.6. As a result, there could be confusion regarding resynchronization coordination and authorization obligations, as well as a gap regarding requirements to implement strategies to address resynchronization issues if events occur differently than specified with the RC's existing restoration plan. Again, Texas RE recommends that if the SDT opts to retire EOP-006-3, Requirement R8, it incorporate the RC's existing resynchronization obligations explicitly into the required restoration plan elements specified in Requirement R1 by added the following:

1.8 Procedures for coordinating and/or authorizing the resynchronization of islanded areas that bridge the boundaries between Transmission Operators and Reliability Coordinators

Likes 0	

Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	
Document Name	
Comment	
This standard is not applicable to Hydro One Networks Inc.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	
Document Name	
Comment	
No Opinion	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	
Document Name	
Comment	
EOP-006-3 does not apply to AE and, therefore, we have no opinion.	
Likes 0	
Dislikes 0	
Response	

5. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-008-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Xcel Energy feels that the verbiage change from "Annual" to "at least every 15 months" in R5 and R7 is unecessary and does not improve the standard. Additionally, it is not consistent with numerous other standards that currently contain "Annual" requirements.	
Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP recommends clarifying the revision of the next to last bullet of Section 1.2 Evidence Retention. How many previous calendar years is evidence to be retained for?	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
EOP-008 R5.1 has always been a bit ambiguous as to when it triggers a required update of the Operating Plan. "Any changes to any part of the Operating Plan" could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle. Langaue could be modeled off the new language in EOP-005-3 R4. For example, the language could be changed to, "An update and approval of the Operating Plan for backup functionality shall take place withing sixty calendar days to reflect changes in the operating plan to items	

in R1 that would change the ability to implement the operating plan."	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
R1: We request further clarification regarding the inclusion of Interpersonal Communications in R1.2.3. Will the the Operating Plan for backup functionality need to also address Alternative Interpersonal Communications? The primary control center for the BA/TOP is required under COM-001-2.1 to have both Interpersonal Communications and Alternative Interpersonal Communications. To follow R1.3, it seems like BA/TOP entities would need to also have Alternative Interpersonal Communications addressed in the Operating Plan for EOP-008-2 in order to keep backup functionality consistent with the primary control center. Also, when operating from the backup, entities still must adhere to Standard COM-001-2.1. If Alternative Interpersonal Communications need to be part of the Operating Plan for EOP-008-2 that should be clear to all entities from the Standard so they know what their obligations are. The current version just says Voice communications, and that can mean something very different than having both Interpersonal Communications and Alternative Interpersonal Communications. R5: See Duke Energy's comment regarding the replacement of "annual" with "at least once each 15 calendar months" in response to question 1 above.	
Likes 0	
Dislikes 0	
Response	
Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Document Name	
Comment	
"Any changes to any part of the Operating Plan" could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle.	
Likes 0	
Dislikes 0	
Response	

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	
Comment	
"Any changes to any part of the Operating Plan" could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
"Any changes to any part of the Operating Plan" could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	No
Document Name	
Comment	
PGE thinks that the 15 month window is too restrictive and will give us less flexibility to schedule the drills outside of storm season, peak load periods, unexpected issues, etc. There is little gained by the more restrictive window, and much flexibility is lost in the ability to work around system demands.	

Likes 0	
Dislikes 0	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Bonneville Power Administration (BPA) has identified a risk regarding R7. Not all utilities perform testing the same. R6 requirement of having independent functionality are not uniformly tested in R7. Some utilities do not completely sever connection to the primary functionality in order to test complete independence of primary and backup functionality. BPA recommends an additional sub-requirement for R7 to explicitly define how to test to ensure uniformity among utilities and mitigate risk of inadvertent dependence on primary functionality.	
Likes 0	
Dislikes 0	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Bonneville Power Administration (BPA) has identified a risk regarding R7. Not all utilities perform testing the same. R6 requirement of having independent functionality are not uniformly tested in R7. Some utilities do not completely sever connection to the primary functionality in order to test complete independence of primary and backup functionality. BPA recommends an additional sub-requirement for R7 to explicitly define how to test to ensure uniformity among utilities and mitigate risk of inadvertent dependence on primary functionality.	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	

The replacement of “annual” with “at least once each 15 calendar months” in R7 introduces additional unnecessary administrative tracking requirements, suggest that this requirement remains an annual requirement.

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	

Comment
Manitoba Hydro suggests to keep using Voice communications for R1.2.3 as it provides more clarity than Interpersonal Communications and eliminates redundancy with R1.2.2. Other type of communication mediums such as email and web messaging would already be covered under R1.2.2 Data communications.

Likes 0	
Dislikes 0	

Response

Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA	
Answer	Yes
Document Name	

Comment
FMPA generally agrees with the revsions proposed for EOP-008, but again believes the defined term Control Center should be used throughout the standard.

Likes 0	
Dislikes 0	

Response

Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes

Document Name	
Comment	
GRU generally agrees with the revsions proposed for EOP-008, but again believes the defined term Control Center should be used throughout the standard.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
We believe the SDT should add language "with respect to loss of control center functionality" in Requirement 7 immediately after "Operating Plan"	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
PJM has concerns with R6 and its implecations to other standards. Specifically, TOP-001-4 and its requirement to maintain redundancy.	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	Yes
Document Name	

Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy generally agrees with and supports the SDT's revisions and clarifications proposed for EOP-008-2. We would like the SDT to consider changing R1.2.2 from, "Data communications" to "Data exchange capabilities" for consistency and alignment with revisions to the upcoming January 2017 enforceable requirements in TOP-001-3 R19 and IRO-002-4 R1 which are required to support the data specification concept in TOP-003-3.	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
(1) We agree with the R1 changes from voice communications to Interpersonal Communication capabilities to align with other NERC standards. (2) We question the need for a change in M1, M2, and M5 from "in force" to "in effect." They appear synonymous. (3) For R5 and R7, we agree with changing annually to 15 calendar months to align with other NERC standards.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6,	

5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	

R1

We agree the revision to R1, Part 1.1. prevents a tertiary Requirement (i.e., already included in EOP -008- 2, R3 and R4).

We agree that in R1, Part 1.2.3., the defined term "Interpersonal Communications" should be used.

R5 and R7

We are supportive of replacing "annually" with "15 months" and believe it provides added clarity.

Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	

We agree with EOP-008-2

Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	

Given the shift in EOP-005-3 and EOP-006-3 away from the mere 'having' a restoration plan to 'developing and implementing' a restoration plan, would it make sense to shift EOP-008-2 R1 away from 'having' to 'developing and maintaining' the Operating Plan? The other requirements concerned with the physical plan remain valid.

Should R7 be modified to ensure consistency with R1.5 time requirement?

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct a test of its Operating Plan at least once every 15 calendar months and shall document the results from such a test. This test shall demonstrate: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality **is less than or equal to two hours**.

7.2. The backup functionality for a minimum of two continuous hours.

Likes 0	
Dislikes 0	

Response

ALAN ADAMSON - New York State Reliability Council - 10

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jack Stamper - Clark Public Utilities - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Dislikes 0	
Response	
Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tina Garvey - Austin Energy - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gregory Campoli - New York Independent System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wes Wingen - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
Requires a rework of the language related to the retention of evidence as "previous calendar years" is ambiguous and open to interpretation. Recommend that language related to the retention of evidence be consistent throughout the NERC standard. That is, "…shall retain evidence for the time period since its last compliance audit."	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
The term "control center" (Purpose statement, Requirement R1, part 1.3, part 1.5, part 1.6, Requirement R2, Measure M2, Requirement R3, Measure M3, Requirement R4, Requirement R6, Measure M6, part 7.1, Evidence Retention section, and the VSL section) should be capitalized as it is a defined term. Texas RE recommends revising Requirement R2 to generically refer to any location capable of providing backup functionality as there are cases where there are tertiary control centers developed. Note that having multiple locations where backup functionality may exist is considered to be, or could be considered to be, an exceptional step in supporting reliability and continuity of reliable operations but there should be an expectation of similar reliability expectations coupled with compliance obligations at these locations.	

As the goal of the Reliability Standards is Reliability, Texas RE recommends revising Requirement R3 and Requirement R4 “reliable operations and subsequent compliance…”

Texas RE suggests Requirement R3 would be cleaner if the information in the parentheses were listed out as subparts. Also, replace "certified Reliability Coordinator operators" with System Operator, which is defined.

Texas RE suggests Requirement R4 would be cleaner if the information in the parentheses were listed out as subparts. Also, replace "applicable certified operators" with System Operator, which is defined.

In the “Evidence Retention” section, the changes made to the Measures do not seem to have been provided here (e.g. Measurement M1 changed “in force’ to “in effect” below the R1 but in this section still shows “in force”…multiple instances that need a quality review). Additionally there is inconsistency in the language (e.g. audit versus compliance activity) in this section as compared to EOP-005.

Likes 0	
Dislikes 0	

Response

6. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Document Name	

Comment

We support NPCC's comments.

Likes 0	
Dislikes 0	

Response

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC

Answer	No
Document Name	

Comment

The SRC suggests that the VSLs for EOP-00-3 be clarified as follows:

R1 – Severe VSL: The Transmission Operator does not have an approved restoration plan OR The Transmission Operator has an approved restoration plan but failed to implement it when a disturbance occurred, in accordance with Requirement R1.

R3 – Lower VSL, Moderate VSL, High VSL and Severe VSL: delete the words “or confirmation of no change” in all of the VSLs to make the language consistent with the deletion of Requirement R3.1.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

(1) For the requirements that added “implement” to the requirement, we disagree with the corresponding changes to the VRFs and VSLs. The reasons for disagreement are captured in previous comments.

(2) For the requirements that were proposed to be retired or requirements that had timelines clarified, we agree with the corresponding VRFs and VSLs.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

EOP-005-3 R3: Adjust the VSLs to match R3 due to the striking of R3.1.

EOP-005-3 R4: **Moderate VSL:** The TOP updated and submitted its restoration plan that would affect implementation of the restoration plan, to the Reliability Coordinator between 91 calendar days and 120 calendar days of an **unplanned** change.

OR

The TOP failed to update and submit its restoration plan that would affect implementation of the restoration plan to the Reliability Coordinator at least 20 calendar days prior to a **planned** change.

EOP-005-003 R4: **High VSL**: The TOP updated and submitted its restoration plan that would affect implementation of the restoration plan, to the Reliability Coordinator between 121 calendar days and 150 calendar days of an **unplanned** change.

OR

The TOP failed to update and submit its restoration plan that would affect implementation to the Reliability Coordinator at least 10 calendar days prior to a **planned** change.

EOP-005-003 R4: **Severe VSL:** The TOP has failed to update and submit its restoration plan that would affect implementation of the restoration plan, to the Reliability Coordinator within 150 calendar days of an **unplanned** change.

OR

The TOP failed to update and submit its restoration plan that would affect implementation of the restoration plan to the Reliability Coordinator prior to a **planned** BES modification.

EOP-006-3 R8: The VSL should match the Standard Requirement R8, not R8.1.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
R4: Duke Energy suggests that the drafting team revisit the language for Severe VSL for R4. It appears that the phrase *"to a planned BES modification"* was left in the VSL, whereas the language used in the other VSL(s) use *"to a planned change".*	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins with the comments of the IRC Standards Review Committee (SRC).	
Likes 1	Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
For EOP-005-3 R1 and EOP-006-2 R1 Severe VSLs, SRP recommends removing the verbiage regarding implementation of the plan. For EOP-005-3 R2, the first 3 VSLs are based on a discrete number, while the Severe VSL also includes the term "half". That causes a potential for contradiction. For example, if an approved restoration plan only identifies 2 entities and 1 of them is not notified of changes, that meets the criteria for both the Lower VSL and the Severe VSL.	
Likes 0	

Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	

ReliabilityFirst provides the following comments for the **EOP-005-3** VSLs:

1. VSL for R1

   i. Requirement R1 has 9 sub-parts but the high VSL only mentions missing 3 sub-parts. This leaves a gap in cases where an entity fails to comply with 4 or more sub-parts. RF suggest the following as an additional "OR" VSL to the Severe VSL

      a. The Transmission Operator has an approved plan but failed to comply with four or more of the requirement parts within Requirement R1.

2. VSL for R6

   i. To further clarify the timing of the High VSL, RF recommends the following modification for the High VSL:

      a. The Transmission Operator performed the verification but did not complete it within [six years].

3. VSL for R8

   i. Since Requirement R8 has a timing component as well "…training at least once each 15 calendar months…", RF recommends adding additional "OR" VSLs to the Severe VSL level as follows:

      a. Severe VSL - The Transmission Operator failed to include within its operations training program, System restoration training at least once within 15 calendar months for its System Operators.

4. VSL for R12

   i. To be consistent with the language in Requirement R12, RF recommends the following language for the Severe VSL

      a. Each Generator Operator with a Blackstart Resource failed to have documented procedures for starting each Blackstart Resource and energizing a bus.

ReliabilityFirst provides the following comments for the **EOP-006-3** VSLs:

1. Requirement R2

   i. RF request clarity around the phrase "or revision" at the end of Requirement R2. Since the RC must perform a review of the restoration plan every 15 calendar months according to Requirement R3, is this considered a revision (thus prompting the RC to distribute the restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days)? If this is the intent, RF recommends the following revision for the SDTs consideration.

a. R2 - The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation, revision [or annual review].

1. VSL for R5
2.
   i. Since the word "notification" is not in Requirement R5, RF suggests removing the second "OR" VSL from each of the VSL Categories and add the phrase "with stated reasons" to the first VSL. Listed below is an example of this addition to the Lower VSL Category:
      a. The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans [with stated reasons] from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt.

Likes 0	
Dislikes 0	

Response

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Document Name	

Comment

It is suggested that the VSLs for EOP-005-3 be revised for clarification as follows:

R1--Severe VSL: The Transmission Operator does not have an approved restoration plan OR the Transmission Operator has an approved restoration plan but failed to implement it when a disturbance occurred, in accordance with Requirement R1.

R3--Lower VSL, Moderate VSL, High VSL and Severe VSL: delete the words "or confirmation of no change" in all of the VSLs to make the language consistent with the deletion of Part 3.1.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion and NYISO

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4; James McFall, Modesto Irrigation District, 3, 6, 4; - Nick Braden

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Karen Yoder - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RF

Answer	Yes
Document Name	

Comment

Note the SDT will need to make changes to EOP-005-3 VSLs to align with FE proposed requirement text changes if the changes are accepted.

Likes 0	
Dislikes 0	

Response

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane

Answer	Yes
Document Name	

Comment

No comments

Likes 0	

Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	

Comment

EOP-005-3:

1. All R3 VSLs should be revised to read as ‘mutually agreed upon’.
2. R4: High VSL should be revised to read as ‘between 121 calendar days and 150 calendar days…’.

Likes 0	
Dislikes 0	

Response

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	

Comment

EOP-005-3:

1. All R3 VSLs should be revised to read as ‘mutually agreed upon’.
2. R4: High VSL should be revised to read as ‘between 121 calendar days and 150 calendar days…’.

Likes 0	
Dislikes 0	

Response

Clay Young - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	Yes

Document Name	
Comment	
EOP-005-3: All R3 VSLs should be revised to read as ‘mutually agreed upon’. R4: High VSL should be revised to read as ‘between 121 calendar days and 150 calendar days…’.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Comments: EOP-005-3: 1. All R3 VSLs should be revised to read as ‘mutually agreed upon’. 2. R4: High VSL should be revised to read as ‘between 121 calendar days and 150 calendar days…’.	
Likes 0	
Dislikes 0	
Response	
Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Andy Bolivar - NextEra Energy - Florida Power and Light Co. - 1,3,5,6 - FRCC,Texas RE,NPCC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Johnny Anderson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ken Simmons - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 9; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Tina Garvey - Austin Energy - 4

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Andrew Gallo - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wes Wingen - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Cooper - Alameda Municipal Power - 3,4 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

EOP-005: Consistent with Texas RE's comments above, the SDT should separate the development and implementation of restoration plans under EOP-005-3's requirements. If the SDT does this, these changes should also flow through the affected VSLs. However, the SDT should at a minimum revise the language in the VSL to reference the revised standard requirements in R1. That is, the VSL, as currently drafted, uses the term "comply." Rather, as Texas RE reads the elements in the VSL, the Lower, Medium and High categories reference a TOP's obligation to incorporate the various restoration plan elements specified in parts R1.1 through R1.9. As such, Texas RE recommends revising the VSLs to make clear that the each violation threshold applies for TOPs not including required elements in their plan. For example, the Lower VSL should read: "The [TOP] has an approved plan, but the plan is missing one of the required elements specified in the requirement parts within Requirement R1."

EOP-006: Please see the comments on EOP-006-3, R1 above. The proposed VSLs do not address a RC's maintenance obligations under R1.

EOP-008: The Requirement R2 Severe VSL should say "control locations".

Likes 0	
Dislikes 0	

Response

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

7. Please provide any additional comments for the EOP Standard Drafting Team to consider, if desired.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	

In EOP-005-3 the effective date of the restoration plan should be defined. Requirement R4 only takes into account the update and the submittal of the TOP plan to the RC for approval. Requirement R4 does not define the effective date of the TOP plan. On reading between the lines, it can be understood that the restoration plan should be effective no more than 120 (90+30) days following an unplanned System modification and prior to the implementation of a planned System modification.

The Drafting Team should consider the addition of a phrase to Requirement R4 to indicate that the TOP plan becomes effective following its approval by the RC.

Requirement R6 of EOP-005-3 requires verification and testing of the restoration plan at least once every five years.

The *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans* recommended the re-verification or re-testing of the restoration plan when there are System changes that could impact the viability of the plan.

The Drafting Team should consider the updating of Requirement R6 according to the recommendation or explain why this recommendation was not retained.

The phrase "or an energized island has been formed on the BES within the Reliability Coordinator Area" needs to be clarified by the Drafting Team regarding Requirement R1 of EOP-006-3.

The spirit of this standard applies most notably to coordination between Reliability Coordinators and between the Reliability Coordinators and their Transmission Operators. Does the "energized island" refer to an island formed that bridges boundaries between two TOPs or an island formed within one TOP in the Reliability Coordinator Area? Is the formation of the island solely in the context of a partial outage?

Likes 0	
Dislikes 0	
Response	

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	

EOP-005-3 in Section C, 1. Compliance Monitoring Process, that the data/retention time frame for R1 (first bullet) is since the "last monitoring activity". This is a moving target for tracking evidence retention. EOP-006-3 does not have the same retention period for the RC similar Requirement. It remains as the "last compliance audit". Would suggest that the drafting team return the retention language for EOP-005-3 R1 back to the 'last compliance audit'.

Likes 0	

Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	
Document Name	
Comment	
Not applicable.	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 6	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	
Document Name	
Comment	

The webinar for Project 2015-08 mentioned that the proposed revisions to EOP-005 and -006 to address the Recommendations from the ***FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans.*** In that regard, Recommendation #2 stated:

2. Verification/testing of modified restoration plan. The joint staff review team recommends that measures be taken (including considering changes to the Reliability Standards) to address the need for re-verification of a system restoration plan when a system change precipitates the need to determine whether the plan's restoration processes and procedures, when implemented, will operate reliably, i.e., when needed to ensure that the restoration plan, when implemented, allows for restoration of the system within acceptable operating voltage and frequency limits. In considering such measures, the types of system changes that could impact reliable implementation of the restoration plan should be taken into account (e.g., identification of a new blackstart generator location or on redefinition of a cranking path). **[Section IV.G]**

R6 states that: “Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years….”while **M6** goes on to state that: “Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with **R6**.”

If the SDT’s intent is to have the Transmission Operator verify its plan following an update triggered by **R4**, then APS recommends requirement R6 be revised to more clearly indicate this expectation as follows:

R6. Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years or as triggered by a revision to its restoration plan following a System modification as defined under requirement R4. Such analysis, simulations or testing shall verify:…”

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Clay Young - SCANA - South Carolina Electric and Gas Co. - 3

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Teresa Cantwell - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	
Document Name	
Comment	
Under Project 2015-08, EOP-005-3 states that organizations will be required to obtain electronic confirmation/verification evidence (receipts) from entities when plans have been transmitted. This will be a challenge considering industry organizations have no control over the entities process once the plans have been received. LCRA is under the position to submit a negative vote with the proposed written revisions until further thought is given and changes are made to remove this requirement	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3; Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
The two separate postings caused confusion because the same project has different due dates and overlapping comment periods. We strongly recommend delaying the posting until all standards are ready. We have concerns that the announcements to industry were not clearly announced and stakeholders may not be aware of the two separate and distinct deadlines for submitting comments and balloting on this project. Thank you for the opportunity to comment.	

Likes 0	
Dislikes 0	

Response

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin, Group Name SRC

Answer	
Document Name	

Comment

ISO-NE voted Negative on EOP-005-3 and EOP-006-3; this is in support of comments submitted here as a member of the SRC; if comments submitted are addressed, ISO-NE would be supportive of the revised Standards.

Likes 0	
Dislikes 0	

Response

Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1

Answer	
Document Name	

Comment

1. In R2 and M2 of EOP-005-3, it is not clear who "their" is referring to in each statement.

2. There are several references to 15 calendar months throughout EOP-005-3. Changing the time period to 15 months does not enhance reliability but does have other negative impacts. In R3, entities already have a set period identified by their RC as to when their restoration plans are due. In R8, changing the requirement from annually to 15 months adds a significant level of complexity by requiring tracking of individual rolling time windows for each operator.

3. In R8.5 of EOP-005-3, training operators on the transition back to normal operations does not provide a reliability benefit commensurate with the level of effort required to develop training. In addition, operator training content is established using the Systematic Approach to Training as required by PER-005-2, R1. Adding training requirements outside of SAT and the PER standard is contrary to the intent of PER-005 and the philosophy of the systematic approach.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	

Document Name	

Comment
Texas RE noticed EOP-005-3 Requirement R2 only appears to only apply when there is a change to entities' roles. Texas RE is concerned those entities where there is not a change would not receive an updated restoration plan and thus have a different plan than other entities. Texas RE recommends providing an updated restoration plan to all entities identified in the plan if there are any changes to the plan. There should be information indicating a change or "no change" in the roles. Texas RE noticed the term "system" is not capitalized in EOP-005-3 Requirements R1.1 and R1.2, but it is capitalized in the RSAW. Since "system" is a defined term in the NERC Glossary, and to be consistent with the RSAW, Texas RE recommends capitalizing the term. Texas RE noticed EOP-005-3 is uses the term "Disturbance" but EOP-006 has no reference to a "Disturbance". Texas RE inquires as to why EOP-006-3 does not mention "Disturbance". Texas RE is concerned with the language in EOP-005-3 Requirement R9 that says: "that are outside of their normal tasks". Specific system restoration training should always take place regardless of whether or not the unique tasks are outside [System Operators'] normal tasks". Texas RE is concerned training might not take place if registered entities do not consider System restoration a unique task. Texas RE requests, in the future, that a full redline be provided for every project. If it is not clear what changed, the requirement language cannot be fully evaluated. Also, Texas RE requests rationale for the changes.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb

Answer	
Document Name	

Comment
None.

Likes 0	
Dislikes 0	

Response

Jennifer Wright - Sempra - San Diego Gas and Electric - 1	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Michael Godbout - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	
We support NPCC's comments. In addition we have the following comments. Comments regarding EOP-006-3 and the concept of "energized island": The phrase “or an energized island has been formed on the BES within the Reliability Coordinator Area” should be clarified by the Drafting Team regarding Requirement R1 of EOP-006-3. As argued in question 1, we support this concept in EOP-006-3 and would like this concept extended to EOP-005-3. However, we would like the concept to be clarified in order to set clear expectations and a common understanding around this concept. We note, for example, that the spirit of EOP-006-3 applies most notably to coordination between Reliability Coordinators and between the Reliability Coordinators and their Transmission Operators. RC- RC : As phrased, would an island on the BES that lies across two RC boundaries trigger R1? The third sentence implies the affirmative. If so, it could be clearer to replace the "within the RC Area" by "within **or partly within** the RC Area" or some other variant. RC -TOP : Does the concept of “energized island” distinguish an island that bridges boundaries between two TOPs and an island formed within one TOP in the Reliability Coordinator Area? Is the formation of the island in R1 solely in the context of a partial outage?	
Likes 0	
Dislikes 0	
Response	

Comments on EOP-005-3 – System Restoration from Blackstart Resources

EOP-005-3 R1:

Each Transmission Operator shall ~~have~~ develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall allow for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the ~~shuts down~~ shutdown area to service. ~~To a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System.~~

Comment:

a) The wording *"develop and implement"* has led to some confusion among entities who only see the requirement (the first sentence) and do not take into account the rest of the requirement and also the measurement of compliance associated with the requirement.

M1 states: Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with R1.

Recommend improved language for EOP-005-3 R1 to alleviate the confusion and provide clarity for the requirement. Such as "maintain" or "make effective," in any case, I believe that the SDT should further define the meaning of "implement" in the requirement.

b) Keep the language *"To a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System."* As *"to restore the ~~shuts down~~ shutdown area to service,"* could have broader implication for restoration of every part of the system down to what level of distribution?

EOP-005-3 R9:

*Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as **performing unique tasks associated with the Transmission Operator's restoration plan that are outside their normal tasks.***

Comment:

a) Recommend improved language adding clarity to the term "unique tasks" – what does this mean? Does this mean restoring islands, synchroscopes, and restoring station power? Or?

<u>Comment on EOP-006-3 – System Restoration Coordination</u>

a) This NERC standard is applicable to Reliability Coordinators therefore I have no comments.

<u>Comment on EOP-008-2 – Loss of Control Center Functionality</u>

See *Draft 1 of EOP-008-2 June 2016:* "Section C. Compliance 1.2 Evidence Retention Bullet #7 page 8 of 15"

Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current and previous calendar years ~~and one previous year,~~ such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement 7.

Comment:

a) Requires a rework of the language related to the retention of evidence as "previous calendar years" is ambiguous and open to interpretation. Recommend that language related to the retention of evidence be consistent throughout the NERC standard. That is, "…shall retain evidence for the time period since its last compliance audit."

SCANA/SCE&G Survey Responses

Questions

1. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-005-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   No

   Comments:

   a. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

   b. The revision to EOP-005 R8 adds the requirement R8.5 "Transition to Balancing Authority for Area Control Error and Automatic Generation Control." We agree with the addition of this requirement and think required training in this area would be good for the industry. One possible concern with the proposed language has to do with when the TOP returns control of the BA Area back to the BA, the BA isn't necessarily going back to Automatic Generation Control right away. Our suggestion would be to reword R8.5 to say, "Transition to Balancing Authority ensuring adequate Area Control Error (ACE) configuration and generation control"

2. Do you agree with the retirements proposed in EOP-005-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   No

   Comments:

Retirement of Requirement 8 removes the requirement for the TOP to seek approval from the RC before resynchronizing areas. Requiring the TOP to coordinate with the RC ensures adequate coordination will occur in order to maintain a reliable system during restoration and therefore it should remain a requirement.

Maybe add subpart to R1 to clarify RC approval of re-synchronization of islands if R8 is removed.

3. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

No

Comments:

a. Most training is conducted on a yearly basis, with certain training required every year. Our training consists of five cycles of training classes. Each cycle is six weeks in order to get all of the operators through each training cycle. At times we conduct specific required training in one cycle verses another cycle. One year it might make sense to have the System Restoration training occur in the spring cycle. Another year, it may work better if they System Restoration training were to occur in the fall cycle. By changing the System Restoration training to, "at least once each 15 calendar months" it limits the ability to move the training from one cycle to another. It would give the operator trainers more flexibility if the training were required annually. That way the operators would receive System Restoration training every year but it would also give the trainers the flexibility to move the training around within the year as needed.

b. EOP-006-3 R1 states: Each Reliability Coordinator shall develop, *maintain*, and implement..
EOP-005-5 R1 states: Each Transmission Operator shall have develop and implement..
We recommend 'develop and implement' language in EOP-005-3 R1 be used in EOP-006-3 R1 also for consistency among the two standards.

4. Do you agree with the retirements proposed in EOP-006-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

No

Comments:

a. One of the most important jobs of the Reliability Coordinator during system restoration is to ensure proper coordination is occurring between TOPs and Reliability Coordinators. Lack of coordination could have a large impact on system reliability during system restoration. The requirement that the RC coordinate or authorize resynchronizing of islands should remain. In the next requirement (old R9) the RC is even required to train on "The coordination role of the Reliability Coordinator and Reestablishing the Interconnection". It seems to be in conflict for the RC to train on the coordination role but not require the TOP to coordinate with the RC when resynchronizing areas (proposed removal of EOP-005 R8) and not require the RC to coordinate the resynchronization of with neighboring TOPs and RCs.

5. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-008-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

No

Comments:
"Any changes to any part of the Operating Plan" could mean that something as simple as a title change, organizational name change, or phone number change could trigger an update or approval of the Operating Plan. The drafting team should take this opportunity to clarify R5.1 in order to require that only substantive changes in the Operating Plan or changes that change the ability to implement the operating plan require an update and approval of the operating plan outside of the normal review cycle.

6. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

Yes

Comments:
EOP-005-3:
a. All R3 VSLs should be revised to read as 'mutually agreed upon'.
b. R4: High VSL should be revised to read as 'between 121 calendar days and 150 calendar days…'.

7. Please provide any additional comments for the EOP Standard Drafting Team to consider, if desired.

Comments: None

Unofficial Comment Form

2015-08 Emergency Operations

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-08 Emergency Opreations; EOP-005-3 – System Restoration from Blackstart Resources, EOP-006-3 – System Restoration Coordination, and EOP-008-2 – Loss of Control Center Functionality**. The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the project page. If you have questions, contact Standards Developer Manager, Sean Cavote (via email), or at (404) 446-9697..

Background Information

Project 2015-08 Emergency Operations (EOP) implements the recommendations of the Project 2015-02 Periodic Review Team (PRT) that resulted from the PRT's review of a subset of EOP Standards. The PRT comprehensively reviewed EOP-004, EOP-005, EOP-006 and EOP-008 to evaluate, for example, whether the requirements are clear and unambiguous.

The Periodic Review also included background information, along with associated worksheets and reference documents, to guide a comprehensive review that resulted in a Standard Authorization Request (SAR) based on the following PRT's recommendations:

- EOP-004-2 – (1) Revise the standard and attachment and (2) retire Requirement R3;
- EOP-005-2 – Revise the standard;
- EOP-006-2 –Revise the standard; and
- EOP-008-1 – Revise the standard.

The four NERC Reliability Standards in the Periodic Review project concerned methodologies for restoring, reporting, and communicating Emergencies. Implementation of revisions and retirements recommended by the EOP PRT clarify the critical methodology requirements for Emergency Operations, while ensuring strong planning, reporting, communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standards, while making the standards more Results-based.

Questions

1. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-005-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

☐ Yes
☒ No

Comments:

Requirement R4: The proposed changes to R4 cause concern for FirstEnergy. The existing FERC approved requirement R4 requires notification by a Transmission Operator (TOP) to its Reliability Coordinator (RC) for a "permanent" system modification (planned or unplanned) "that would change the implementation of its restoration plan." The proposed revisions by the drafting team, while well intended, shifts the emphasis to changes that affect "ability to implement" the TOP restoration plan regardless of whether or not the system modification (planned or unplanned) is temporary or permanent. This change would cause numerous re-writes of restoration plans by TOPs and approval reviews by RCs resulting from planned maintenance outages of BES transmission facilities (lines, transformers, generators, etc.), many of which are short duration outages. FirstEnergy believes it is important to retain the "permanent" modification aspect of the existing FERC approved requirement. The proposed change results in an overly burdensome requirement without significant improvement to BES reliability.

FirstEnergy does support the intended 90-day notification for unplanned changes and the minimum 30-day lead-time from the effective date of planned changes.

FirstEnergy proposes the requirement be written as follows:

R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect permanent System modifications that would change the implementation of its restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications.

4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

A red-line version of our proposed changes is provide in the attached version of FE comments.

FE Propopsed R4 - Redline to Draft 1:
R4. Each Transmission Operator shall update and submit to its Reliability Coordinator for approval of its restoration plan to reflect permanent System modifications that would change the ~~ability to~~ implemention of its restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

4.1. No more than 90 calendar days after the Transmission Operator identifies any unplanned System modifications.

4.2. No less than 30 calendar days prior to the Transmission Operator's implementation of planned System modifications.

2. Do you agree with the retirements proposed in EOP-005-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

☒ Yes
☐ No

Comments:

3. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

☒ Yes
☐ No

Comments:

4. Do you agree with the retirements proposed in EOP-006-3 of Requirement 7 and Requirement 8? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

☒ Yes
☐ No

Comments:

5. Do you agree with the revisions and clarifications made by the EOP Standard Drafting Team to standard EOP-008-1? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

   ☒ Yes
   ☐ No

   Comments:

6. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in the proposed standards? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs your recommendation and explanation.

   ☒ Yes
   ☐ No

   Comments:
   Note the SDT will need to make changes to EOP-005-3 VSLs to align with FE proposed requirement text changes if the changes are accepted.

7. Please provide any additional comments for the EOP Standard Drafting Team to consider, if desired.

   Comments: