Comment Report

Project Name: Standards Efficiency Review | SAR

Comment Period Start Date: 6/7/2018

Comment Period End Date: 7/10/2018

Associated Ballots:

There were 40 sets of responses, including comments from approximately 147 different people from approximately 102 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the recommendations and rationales to retire the proposed requirements? If not, please state the standard(s) and requirement number(s) in your response(s) along with your rationale(s) for not retiring the requirement(s).

2. Are there any additional requirements that you contend could be retired without modifying any other requirement(s) and/or standard(s)? If so, please state the standard(s) and requirement number(s) in your response(s) along with your rationale(s) for retiring the requirement(s).

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Florida Municipal Power Agency	Brandon McCormick	3,4,5,6	FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Greg Froehling	Rayburn Country Electric Cooperative, Inc.	6	MRO

					Tara Lightner	Sunflower Electric Power Corporation	1	MRO
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
					Susan Sosbe	Wabash Valley Power Association	3	RF
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
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO

					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
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
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
New York Independent System Operator	Gregory Campoli	2		ISO/RTO Standards Review Committee	Gregory Campoli	NYISO	2	NPCC
					Ben Li	IESO	2	NPCC
					Kathleen Goodman	ISONE	2	NPCC

					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Terry BIlke	Midcontinent ISO, Inc.	2	MRO
					Ali Miremadi	CAISO	2	WECC
DTE Energy - Detroit Edison Company	Jeffrey DePriest	3,4,5		DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Daniel Herring	DTE Energy - Detroit Edison Company	4	RF
JEA	Joe McClung	1,3,5	FRCC	JEA Voters	Ted Hobson	JEA	1	FRCC
					Garry Baker	JEA	3	FRCC
					John Babik	JEA	5	FRCC
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Southwest Power Pool, Inc. (RTO)	Matthew Harward	2	MRO,SERC	SPP Standards Review Group	Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					Shannon Mickens	Southwest Power Pool, Inc.	2	MRO
					Mike Kidwell	Empire District Electric	1,3,5	MRO
					Tara Lightner	Sunflower Electric Power Corporation	1	MRO
					Louis Guidry	Cleco Power LLC	1,3,5,6	SERC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and Hydro One	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Dermot Smyth	Con Ed - Consolidated	1,5	NPCC

						Edison Co. of New York		
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
PSEG	Sean Cavote	1,3,5,6	NPCC,RF	PSEG REs	Tim Kucey	PSEG - PSEG Fossil LLC	5	NPCC
					Karla Barton	PSEG - PSEG Energy Resources and Trade LLC	6	RF
					Jeffrey Mueller	PSEG - Public Service Electric and Gas Co.	3	RF
					Joseph Smith	PSEG - Public Service Electric and Gas Co.	1	RF
PPL - Louisville Gas and Electric Co.	Shelby Wade	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					Dan Wilson	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Lower Colorado	Teresa Cantwell	1,5		LCRA Compliance	Michael Shaw	LCRA	6	Texas RE
					Dixie Wells	LCRA	5	Texas RE

River Authority					Teresa Cantwell	LCRA	1	Texas RE

1. Do you agree with the recommendations and rationales to retire the proposed requirements? If not, please state the standard(s) and requirement number(s) in your response(s) along with your rationale(s) for not retiring the requirement(s).

Michael Puscas - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	

ISO-NE thanks the Standard Efficiency Review (SER) teams for all their hard work reviewing and analyzing the NERC Standards and requirements for possible retirements, especially if they do not contribute to the effective and efficient operation of the electric system. ISO-NE agrees with the majority of the retirement recommendations of the SER teams in all but a few instances. These are listed below:

INT-009-2.1 R1, R2, R3 (OP) – Regarding R1, retirement was not discussed by the Project 2017-04 Interchange Scheduling and Coordination Periodic Review Team. INT-009-2.1 R1 pointed to language from INT-010-2.1 R1 and would need to be modified if INT-010-2.1 R1 is retired. If INT-009-2.1 R1 is retired, this would be a moot point. Retirement of R3 was not proposed as well. Since this operations and planning (OP) analysis does not discuss R1 and R3 in Real-Time, will the requirements remain due to their real-time applicability? Was there a reconciliation between RT and OP?

Generally, it was not clear to ISO-NE subject matter experts that all three SER subteams (Operations Planning, Real-Time, and Long Term Planning) worked together and discussed and agreed on all NERC Standards and requirements. Further, it was not clear if there was unanimous agreement with the retirement recommendations among all the three subteams. If all three subteams did meet, and if they did agree, then it was not clear in the original SAR and this should be emphasized and or clarified in future releases of the SAR or minimally in a summary of industry comments.

INT-010-2.1 R1. – We recommend keeping the language from R1 stating: "If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required." If the final decision is to retire INT-010-2.1 in its entirety, coordination with NAESB needs to occur. NAESB Business Practice Standard WEQ-004-1.7 specifically references INT010-2.1 R1.

Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5 - WECC	
Answer	No
Document Name	
Comment	

FAC-003-4 R5, R6 and R7

Rationale:

BC Hydro acknowledges the Standard Efficiency Review (SER) Team's efforts to review and analyze the NERC Standards and offers the following on its recommendation to retire the requirements R5, R6, and R7 of FAC-003-4.

In BC Hydro's view, the value of FAC-003-4 is to have requirements in place to avoid problems before they occur and R5, R6, or R7 are core to identifying risks and addressing them in a timely manner to avoid forced outages caused by vegetation. R5, R6 and R7, along with R4 are risk-based requirements that support R1/R2. In BC Hydro's experience with past audits, focus from the auditors has been to confirm that patrols/inspections are completed in a timely manner (R6). Further, they have sought confirmation that inspection findings get incorporated into required maintenance in an annual plan (R7) with evidence that the annual plan has been completed and that any changes are documented taking into account potential risks.

R1 and R2 are performance-based requirements and essentially a confirmation, through lack of documented outages or encroachments into the MVCD, that vegetation is being maintained as required. However, any such outage is a lagging indicator after a problem has occurred. It seems prudent to emphasize R6 and R7 as leading measures that a utility has sufficient maintenance controls in place to avoid vegetation reliability issues. Some evidence in R4, R5, and R6 and even parts of R7 could overlap with R1/R2. However, in BC Hydro's experience, there is a lot of unique evidence required, for R7 in particular, not covered in any of the other requirements.

R3 is a competency based requirement that documents that a utility has a vegetation management program in place that addresses risks known to affect reliability. Auditors have looked at this in the past but once they have confirmed a utility has a program in place, their focus shifts to documenting that the program is followed – namely R4, R5, R6, and R7.

BC Hydro recommends that FAC-003-4 retain the requirements R5, R6 and R7 as this is the best way of minimizing the risks of a cascading reliability failure on the interconnected grid from vegetation encroachments.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 3,5

Answer	No
Document Name	

Comment

AEP supports the work and overall recommendations of the Standards Drafting Team with the following qualifiers:

AEP is unsure that PRC-004-5(i) R4 meets the drafting team's "Evaluation Criteria for Retiring Reliability Standards Requirements", as the declaration of "no cause found" is made only within this obligation (i.e. "is not redundant"). Regarding the reliability rationale, we would agree that not all investigative actions in and of themselves improve reliability, however the ability to track investigative actions over an extended period of time ensures more riguer is applied to the investigative progress.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment	
SRP does not agree with the recommendations to retire FAC-003-4 R5, R6 & R7. Failure by Registered Entities to take corrective actions, annually inspect, or complete 100% of their annual work plan could introduce system hazards, interruptions or failures.	
Likes 0	
Dislikes 0	
Response	
Tara Lightner - Sunflower Electric Power Corporation - 1 - MRO	
Answer	No
Document Name	
Comment	
See ACES and SPP's comments.	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	
Comment	
PJM has concerns with the proposed retirement of NUC-001-3 Requirement R1, since the Requirement clarifies the Nuclear Plant Generator Operator's (NPGO) responsibility for providing the Nuclear Plant Interface Requirements (NPIR) (new or revised) to Transmission Entities. The SER's rationale for retirement of R1 references R2 as being sufficient. However, R2 as currently written, does not clearly indicate whose responsibility it is to provide the NPIRs (only that NPIRs are mutually agreed to by the NPGO and Transmission Entities, and incorporated in Agreements). This is an important clarification that should remain in R1 or should be moved to R2 (if R1 is retired).	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	No

Document Name	

Comment
JEA appreciates the effort of the SER Team and agrees with the recommendations and rationales to retire the proposed requirements with the exception of two comments: 1) JEA disagrees with the rationale for the retirement of PRC-004-5(i) R4. This requirement applies only when the cause of a Misoperation has not been determined and requires the TO/GO/DP to perform investigative actions every two quarters until a cause is identified OR a declaration is made that no cause was identified. The SAR states, “the tracking of investigative actions do not improve reliability” and “further investigation(s) using the same event data are unlikely to lead to identification of the cause.” But, investigative actions do improve reliability if they result in the identification of a cause. If no cause is determined, the TO/GO/DP can simply declare that no cause was identified, thereby satisfying the requirement. The SAR also states, “If additional Misoperation(s) occur, new investigation(s) using the additional event data would be triggered”, but the intention of the investigative actions is to determine a cause to prevent future Misoperations rather than taking a wait-and-see approach to Misoperations. 2) MOD Standards a. JEA requests clarification on the MOD retirements proposal on page 10 of the SAR. These requirements were consolidated into MOD-001-2 in project 2012-05, but is the intention to merely withdraw the February 10, 2014 petition related to MOD-001-2 or to withdraw the petition AND retire the listed requirements? b. Also, based upon the project scope of page 2, all requirements for MOD-001-1a (and MOD-001-2), MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, and MOD-030-3 are being proposed for retirement, but the list on page 10 has excluded MOD-028-2. Suggestion: Modify the second sentence to read: “We recommend that NERC withdraw the February 10, 2014 petition related to MOD-001-2 and retire all requirements of MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, and MOD-030-3.”

Likes 0	
Dislikes 0	

Response

Ruth Miller - Exelon - 1,3,5,6	
Answer	No
Document Name	

Comment
Exelon agrees with the exception of NUC-001-3 R1: *Exelon has concerns with the proposed retirement of NUC-001-3 Requirement R1, since the Requirement clarifies the Nuclear Plant Generator Operator’s (NPGO) responsibility for providing the Nuclear Plant Interface Requirements (NPIRs) (new or revised) to Transmission Entities. The SER’s rationale for retirement of R1 references R2 as being sufficient. However, R2 as currently written, does not clearly indicate whose responsibility it is to provide the NPIRs (only that NPIRs are mutually agreed to by the NPGO and Transmission Entities, and incorporated in Agreements). This is an important clarification that should remain in R1 or should be moved to R2 (if R1 is retired). The NPIRs are based on the licensing requirements (licensing basis) of the plant and therefore the NPGO needs to retain clear ownership of and maintenance of the NPIRs. ”*

Likes 0	

Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	

AZPS appreciates the Standards Efficiency Review Drafting Team's hard work and supports a majority of the proposed retirements. Since the frequency and scope of the System Restoration Training outlined in EOP-005-3 R8 is not duplicated in any other standard, AZPS suggests the review team consider if professional judgment on a per entity basis is sufficient to determine the scope and frequency of its restoration training or if this would be better suited to be promulgated by another mechanism, such as via a reliability standard, as is.

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

IESO thanks the Standard Efficiency Review (SER) teams for all their hard work reviewing and analyzing the NERC Standards and requirements for possible retirements. The IESO agrees with the majority of the retirement recommendations of the SER teams in all but a few instances. These are listed below:

INT-009-2.1 R2

The SAR rationale is that it is redundant with NAESB business practices. NAESB is not regulatory and, therefore, we are not measured by compliance to NAESB. Furthermore, we do not design our business practices around NAESB rules.

While NAESB is more stringent, during reliability curtailments, we need the flexibility given to us by INT-010. This standard allows us to take action to address a reliability need and manage the e-tags after the concern has been addressed – allowing us to manage the e-tags later. We still need this flexibility as the e-tag system does not feed our dispatch tool directly and we would not want to be the "hold up" for a reliability curtailment so we can line up e-tag with our dispatch tools.

IRO-002-5 R4

This is fundamental to how we manage the grid. In the absence of this standard the RC's ability to monitor its BES area may become unavailable or deteriorated with no knowledge to the system operator.

IRO-008-2 R6

When and RC, TOP or BA becomes aware another RC is exceeding an SOL or an IROL that RC, TOP or BA may need to take mitigating actions to maintain reliability, therefore we disagree that with the SAR rationale that this requirement is administrative in nature and does provide reliability benefit. Keeping impacted entities informed in a timely fashion is good operating practice.

TOP-001-4 R16

This is fundamental to how we manage the grid. In the absence of this standard the TOP's ability to monitor its BES area may become unavailable or deteriorated with no knowledge to the system operator.

TOP-001-4 R17

This is fundamental to how we manage the grid. In the absence of this standard the TOP's ability to monitor its BES area may become unavailable or deteriorated with no knoweledge to the system operator.

Likes 0	
Dislikes 0	

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	No
Document Name	

Comment

MOD Standards

Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E/KU) strongly supports the recommendation to retire all of the MOD standards listed in the ‘Project Scope’ section of the SAR (MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, and MOD-030-3). However, in the ‘Detailed Description’ section of the SAR, the SER does not seem to provide a comprehensive justification for the retirement of the

MOD standards, nor to explain why the SER team recommends that NERC withdraw the February 10, 2014 petition to FERC related to MOD-001-2 (“2014 MOD-001-2 Petition”). It is confusing that justifications that were articulated in Project 2012-05 comprise a major part of the justifications in the ‘Detailed Description’ in this SAR, right after recommending that the 2014 MOD-001-2 Petition (which is based on Project 2012-05) be withdrawn. Additionally, MOD-028-2 seems to have been inadvertently omitted from the list of MOD standards being requested to be retired in the ‘Detailed Description’ section. Further, the ‘Detailed Description’ indicates that Project 2012-05 addressed MOD-029-2a and MOD-030-3; strictly speaking, the 2014 MOD-001-2 Petition covered prior versions of MOD-029 (version 1a) and MOD-030 (version 2).

Lastly, it is important that the SER Team carefully consider and clearly articulate the basis for requesting that duplicative and non-reliability related requirements in these MOD standards NOW be eliminated, in light of the fact that this duplication and the commercial nature of these inter-related standards is probably already well known to FERC. Further, if the 2014 MOD-001-2 Petition is being requested to be withdrawn (which LG&E/KU support because this will compel FERC to consider a new petition for retirement or elimination of all of these related MOD standards, including MOD-001), there should be a clear explanation of this request.

VAR-001-4.2 R2

Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E/KU) strongly disagrees with the proposed retirement of VAR-001-4.2 R2 because requiring each Transmission Operator to schedule, provide, and have evidence of scheduling sufficient reactive resources to regulate voltage levels under normal and Contingency conditions is necessary for the reliability of the BES. Reactive power resources are required to maintain voltage stability on the BES. Therefore, removing the requirement to ensure that each Transmission Operator schedules and provides sufficient reactive resources and has the documentation that sufficient reactive resources have been scheduled will be harmful to ensuring the reliability of the BES. Instead of retiring VAR-001-4.2 R2, there should be additional guidance (i.e. Implementation Guidance) to suggest how the transmission control center complies with R2.

Likes 0	
Dislikes 0	

Response

Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer	No
Document Name	

Comment

FAC-008-3 Requirement R8 – PSEG does not support retirement of Requirement R8.2. It is PSEG’s opinion that Requirements R.8.1.2 and R8. 2 are not duplicative of TOP-003-3 Requirements R1 or R5 or IRO-010-2 R1. FAC-008-3 Requirement R8.2 necessitates that TOs provide to their associated RCs, PCs, TPs, TOs and TOPs the Requirement R8.1.2 “identity of the most limiting equipment of the Facilities,” Requirement R8.2.1 “identity of the existing next most limiting equipment of the Facilities,” and Requirement R8.2.2 “Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1,” whereas the TOP-003-3 or IRO-1010-2 standards do not appear to have this requirement.

IRO-010-2 Requirement R1 specifies the types of data that an RC collects from applicable entities, so that the RC may perform OPAs, RTM and RTAs. The OPA RTM and RTA definitions (in the NERC Glossary of Terms) each mention “Facility Ratings” as an input (into OPA’s, RTM and RTA’s). However, neither IRO-010-2, Requirement R1, nor the OPA, RTM and/or RTA definitions (in the NERC Glossary of Terms) contain the level of specificity in FAC-008-3 Requirement R8 (to “identity the most and the existing next most limiting equipment of the Facilities” and “the Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1”). Similarly, TOP-003-3 Requirement R5 requires identified entities to fulfill a data specification provided by a BA or TOP so that OPAs, RTM, and RTA’s may be performed. As in the case of IRO-010-2 Requirement R1 and the OPA, RTM and RTA definitions, TOP-003-3 does not require identification of the most and the existing next most limiting equipment of the Facilities and the Thermal Rating for the next most limiting equipment identified in FAC-008-3 Requirement R8, Part 8.2.1.”

Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	No
Document Name	
Comment	

<u>COM-002-4 R2</u>

Hydro One does not object to addressing System Operator training/competency requirements in PER-005-2; however, Hydro One does not support retirement of COM-002-4 R2 prior to having a revised and approved revision to PER-005 that clearly states the training/competency requirements, and their associated components.

COM-002-4 R2 states a minimum competency requirement for System Operators. Hydro One recommends that minimum competency requirements be clearly stated in future revisions of PER-005. Also, developing a minimum criteria for systematic approach to training is helpful (not just in guidelines).

<u>EOP-005-3 R8</u>

Similar to the above, Hydro One does not object to addressing System Operator training/competency requirements in PER-005-2; however, Hydro One does not support retirement of EOP-005-3 R8 prior to having a revised and approved revision to PER-005 that clearly states the training/competency requirements, and their associated components.

EOP-005-3 R8 states a minimum competency requirement for System Operators. Hydro One recommends that minimum competency requirements be clearly stated in future revisions of PER-005. Also, developing a minimum criteria for systematic approach to training is helpful (not just in guidelines).

<u>FAC-003-4 R5</u>

Hydro One does not support retirement of FAC-003-4 R5.

R5 is specifically incorporated in FAC-003-4 to address situations (constraints that may lead to a vegetation encroachment into MVCD) that may occur outside the control of Transmission Owners preventing them from performing planned vegetation management work.

R5 requires Transmission Owners to take corrective actions rather than taking no action. The requirement also clarifies to the auditors that constraints do not cause non-compliance, as long as the entity takes the corrective actions to address the constraints. Taking no action is not an option.

<u>FAC-003-4 R6</u>

Hydro One does not support retirement of FAC-003-4 R6.

R6 specifies a minimum detective control (inspection) that Transmission Owners must implement to assess the condition of the entire ROW with respect to vegetation. Inspection of ROW allows for assessment of identifying imminent threats, determine future work, and evaluate recently-completed work.

Hydro One believes that FAC-003 should account for differences among entities in vegetation growth when setting the periodic inspection requirement. As an example, an inspection frequency of once per calendar year may be appropriate for an ROW bounded by dense vegetation while it may not be appropriate for an ROW that goes through a desert.

Hydro One believes that retaining such a requirement is important to allow for justifying the need for having such inspections to regulators when applying for transmission rates to the regulator.

Hydro One believes that not having inspections as a component of vegetation management program will result in reduced reliability over time since grow-ins, deficiencies or imminent threats may not be detected in a timely manner.

FAC-003-4 R7

Hydro One does not support retirement of FAC-003-4 R7.

R7 specifies a minimum preventative control (annual work plan/program) that Transmission Owners must prevent encroachment into MVCD. The word "annual" is important since it ensures that vegetation management work is performed consistently. In the absence of a specified frequency, there is an increased risk that entities delay performing vegetation management work required to maintain reliable operation of BES.

Annual vegetation work plan goes hand in hand with the inspection requirement and allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation, and other environmental factors.

FAC-008-3 R8

Hydro One supports retirement of FAC-008-3 R8.

PRC-004-5(i) R4

Hydro One agrees that administrative burden associated with tracking open investigations and their periodic activities do not contribute to reliability.

The intent of PRC-004-5(i) R4 is to require the entity to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

Hydro One believes that this requirement should be revised to state that the entity must continue the investigation for unknown causes in light of new information becoming available or a similar event occurring again. Performing investigative actions every two calendar quarters without new information does not make sense and may result in valuable resources being spent on administrative work.

PRC-015-1

Hydro One supports retirement of this standard.

PRC-018-1

Hydro One supports retirement of this standard.

PRC-019-1 R1

Hydro One supports retirement of PRC-019-2 R1.

TOP-001-4 R19

Hydro One supports retirement of TOP-001-4 R19.

VAR-001-4.2 R3

Hydro One supports retirement of VAR-001-4.2 R3.

It may be helpful to clarify how this effort relates to the standard grading efforts conducted by the Periodic Standing Review Team, if there is a relation at all. Secondly, it may also be helpful if the SER team clarifies what Phase II entails, or can provide a roadmap transitioning from Phase I to Phase II.

Likes 0	
Dislikes 0	
Response	

Matthew Harward - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group

Answer	No
Document Name	
Comment	

The SPP Standards Review Group ("SSRG") agrees with all recommendations for retirement except for IRO-006-5, which includes a rationale that may leave an unintended gap in the requirements. The SAR justifies retirement of IRO-006-5 based on redundancy with R2 of IRO-001-4; however, the requirements for IRO-006-5 and IRO-001-4 R2 are structured to be mutually exclusive and satisfy different purposes. IRO-001-4 R2 is narrowly drawn to require the applicable functional entity to comply with "*its* Reliability Coordinator's Operating Instructions…(emphasis added)" and implies an operating instruction existing intra-interconnection; whereas IRO-006-5 is intended to apply generally to interchange transactions from *any* [Reliability Coordinator] *in another Interconnection* (emphasis added)" and is across Interconnection boundaries (i.e., ERCOT RC to Eastern RC). As IRO-001-4 R2 and IRO-006-5 each applies to separately defined purposes, retiring IRO-006-5 without mitigating this discrepancy may create an unanticipated gap that cannot be satisfied by current IRO-001-4 R2.

Notwithstanding the above, the SSRG agrees with retirement of IRO-006-5 if the underlying requirement can be consolidated with another standard. Therefore, the SSRG recommends that IRO-006-5 be removed from Phase 1 and reviewed during Phase 2 of the SER; and further proposes that either IRO-001-4 R2 could be expanded, or IRO-014-3 may be appropriate, to include the IRO-006-5 requirement.

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	

MOD-001-2: Duke Energy disagrees with the proposal to withdraw NERC's February 10, 2014 petition related to MOD-001-2. MOD-001-2 was developed to address directives in Order No. 729 to modify certain aspects of the MOD A standards and to consolidate the MOD A standards into a single standard covering only the 'reliability-related impact of ATC and AFC calculations'. The consolidated approach was intended to maintain NERC's focus on developing and retaining requirements that support the reliable operation of the Bulk-Power System (BPS). This standard is needed for ATC calculation and coordination methodology. Removal of this standard could prompt entities to redefine how they operate their values as well as hindering entities from having the ability to monitor the flowgates of neighboring entities. Entities need to be able to know their neighbors' impact on the grid with respect to Transfer Capabilities. Furthermore, only Regulated utilities fall under the purview of NAESB practices, which would dilute the power to make entities comply. Lastly, removal of MOD-001-2 would mean that the NAESB standards have no complimentary NERC standards and it could potentially delay further consideration by FERC in relief of the NERC ATC standards. In addition, the MOD-001-2 puts requirements on an entity to provide data and answer questions related to the calculation of AFC, ATC, TFC, or TFC by a requesting entity. If MOD-001-2 is withdrawn, there will be no requirement for entities to provide data or respond to requests. Though ATC is primarily a business mechanism, the calculation of ATC, the margins involved (TRM predominantly), and assumptions used are based off of reliability needs. The purpose of ATC is to determine the maximum transfer capability that can be utilized without jeopardizing the BES and reducing potential SOL exceedances. The retirement of MOD-001-2 and the currently enforceable ATC-related standards (MOD-004-1, MOD-008-1, MOD-030-2) could lead to additional burden on the RC and TOPs in real-time as inadequate reliability margins and assumptions may be included in the calculation of ATCs causing more congestion management actions (TLRs) to mitigate transmission issues.

FAC-013-2: Duke Energy disagrees with the proposal regarding FAC-013-2. This standard was developed in response to FERC Directives in Orders 693 and 729. In the Orders, FERC directed NERC to establish a standard requiring Planning Coordinators to calculate transfer capability in the planning horizon (years one through five) and communicate the results. We disagree with the notion that FAC-013-2 has no bearing on reliability of the BES. In the FAC-013-2 — Planning Transfer Capability White Paper that was drafted during development of the standard, the standard's benefit to reliability is stated:

"Further, FAC-013-2 requires that a Planning Transfer Capability Methodology Document (PTCMD) be developed for the calculation of Planning Transfer Capabilities (PTC) beyond 13 months in the future to provide additional information for the Planning Coordinator to use in planning for BES reliability."

Another pertinent excerpt from the White Paper mentions how FAC-013-2 covers aspects of grid reliability not covered in the TPL standards:

"The TPL planning standards do not specify the need to document transfer capability calculation methods that may be used in the planning horizon. To cover that aspect of planning for BES reliability, the FAC-013-2 standard specifies that Planning Coordinators must perform PTC calculations as part of the planning process, that the method must be documented and shared with other entities as specified in the standard."

Lastly, see the quote from the White Paper below that further illustrates the necessity of FAC-013-2, and how it helps address past concerns from FERC.

"The application of FAC-013-2 will provide PTC values that are an indicator of the robustness of the future transmission system and facilitate communication between adjacent Planning Coordinators. It will result in meeting FERC's concerns regarding transfer capability in the planning horizon and provide important information that Planning Coordinators will be able to apply in their efforts to reliably plan the BES."

Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA appreciates the opportunity to comment to the NERC Standards Effectiveness Review (SER) team on the path forward specifically concerning MOD-001-2 and the associated MOD standards (MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3.) At this time, BPA does not support the recommendation that NERC withdraw the February 10, 2014 petition to FERC related to MOD-001-2. As a result of this NERC petition, NAESB has drafted WEQ-023 Modeling Business Practice Standards based on the MOD-001-2 Reliability Standards in close coordination with NERC.   BPA was an active participant in that process. BPA strongly supports the overall effort to migrate the commercial and business aspects of the NERC MOD Reliability Standards into corresponding NAESB Business Practice Standards, a position BPA filed on 09/26/16 in response to the FERC Notice of Proposed Rulemaking (156 FERC ¶ 61,055).   In that NOPR, FERC makes clear that the status of the NAESB WEQ-023 Modeling standards and the NERC MOD-001-2 standards are now intertwined.   Both are under consideration as part of FERC's overall inquiry into ATC calculations. This includes Docket No. RM14-7-000, dealing with the original February 10, 2014 petition, as well as a related inquiry into ATC from Docket No. AD15-5-000.   BPA recommends FERC address the overall ATC topic currently pending these dockets. FERC guidance on the overall direction of ATC standards is overdue and essential before NERC and/or NAESB invest further resources into companion standards.   However, if NERC were to proceed with modifying its approach to the February 10, 2014 petition, BPA urges NERC to closely collaborate with NAESB so there is a joint recommendation moving forward to FERC.

BPA agrees that the requirement INT-004-3.1 'R3' can be retired assuming that the NERC Pseudo Tie Coordination Reference Document is retained and IRO-010 Applicability Entities remain unchanged.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	

COM-002-4 R2: The training addressed in COM-002 is initial training that is required to take place prior to the individual operator issuing an Operating Instruction. PER-005 addresses continuous learning but is not required PRIOR to an operator issuing and Operating Instruction. Therefore, it is not addressed in PER-005 and should not be retired.

EOP-005-3 R8: This requirement includes specific critical topics that are to be included in System restoration training. While it is unlikely that System restoration training would not be included in the Systematic approach to training required in PER-005, the specifics required in EOP-005-3 may unintentionally be overlooked. The SER team should re-evaluate the retirement of this requirement.

EOP--006-3 R7: Same comment as EOP-005-3 R8.

FAC-003-4 R5, R6, R7: The controls built into requirements R5, R6 and R7 ensure reliability and compliance with R1 and R2. In absence of these controls, the likelihood of Vegetation encroachment may increase.

FAC-008 R8: R8, part 8.2 requires specific information be provided that is not required by MOD-032. Specifically the next most limiting equipment information.

FAC-013-2 R1, 2, 4, 5, 6: WECC agrees with the justification provided by the SER team, but suggests that consideration be given to addressing the failures the language of the requirements rather than retirement.

IRO-006-5 R1: IRO-001-4 R2 does not address RC complying with directives from entities in other inteconnections. It addresses applicable entities complying with Operating Instructions from their own RC. IRO-006-5 R1 addresses a different situation and therefore should not be retired.

PRC-019-2 R1: Retirement of R1 will require a re-write of R2. Also R2 references R1 and R2 has no test specifications contained in R1

TOP-001-4 R19 and R22: Retiring would lead to a potential failure of TOP-002-4 R1 and TOP-003-3 R5 in absence of having data exchange capabilities.

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 1,3,5,6

Answer	No
Document Name	

Comment

FAC-003 R5, R6 and R7: disagree unless the best practice controls are added to R1 and R2

PRC-004 R4: Disagree because having a timely investigation and discussion with vendor can potentially prevent a reoccuring misoperation. New information or event data becoming available should be made part of this analysis

PRC-018 R6: Disagree because PRC-018 R6 (Maintenance and testing) doesn't match to PRC-002 R12. Waiting for a DME to fail instead of a preventative M&T program may not be the best approach

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
TVA appreciates the efforts of the SER team and the opportunity to comment on the team's recommendations. While TVA is generally supportive of the proposed retirements, we raise the following concerns. **INT-004-3.1 (All)** It is our recommendation that INT-004.3.1 not be retired until North American Standards Board (NAESB) Wholesale Electric Quadrant (WEQ) Business Practice Standard WEQ-004, version 3.1 has been approved by FERC. FERC has not issued a final ruling for Docket RM05-5-25: NAESB Standards for Business Practices and Communication Protocols for Public Utilities (Notice of Proposed Rulemaking - July 21, 2016), which addresses NERC recommendations. It is TVA's recommendation that the retirement of INT-004-3.1 should be concurrent with a final ruling for RM05-5-25, accepting version 3.1 of WEQ-004. A SAR should be submitted addressing removing the PSE from INT-004-3.1 A. 4. 4.2 and replacing the Purchasing Selling Entity with the Balancing Authority. **INT-010-2.1 (All)** It is our recommendation that INT-010-2.1 not be retired until North American Standards Board (NAESB) Wholesale Electric Quadrant (WEQ) Business Practice Standard WEQ-004, version 3.1 has been approved by FERC. FERC has not issued a final ruling for Docket RM05-5-25: NAESB Standards for Business Practices and Communication Protocols for Public Utilities (Notice of Proposed Rulemaking - July 21, 2016), which addresses NERC recommendations. INT-010-2.1 ensures that BAs under a reserve sharing agreement submit an eTag within 60 minutes for a covered loss of resources or other reliability needs. It is TVA's recommendation that the retirement of INT-010-2.1 should be concurrent with a final ruling for RM05-5-25, accepting version 3.1 of WEQ-004. **MOD-001-1a (All)** **MOD-004-1 (All)** **MOD-008-1 (All)** **MOD-030-3 (All)** TVA disagrees with the retirement of these standards at this time. Until a resolution is reached on NAESB's WEQ-023, and these items are incorporated by reference per the FERC Commission, retirement of these MOD Reliability Standards would leave a significant gap of reliability of ATC in the industry. WEQ-023 (submitted under Version 003.1) was not approved by the Commission to be incorporated by reference at this time and is being considered under an overall inquiry into ATC calculation. This leaves the standard, as written in NAESB as voluntary. MOD-001-2 was drafted with the mindset of leaving only reliability aspects of ATC under NERC oversight and WEQ-023 being approved by the Commission. If MOD-001-2 is withdrawn, there would be no reliability push for ATC requirements under FERC and could potentially cause further delay. Removal of these standards could impact the transparency that is established with sharing data with neighbors as well. According to Project 2012-05 ATC Revisions (MOD A), MOD-001-2 was developed to address directives in Order No. 729 to modify certain aspects of the MOD A standards and to consolidate the MOD A standards into a single standard covering only the 'reliability-related impact of ATC and AFC

calculations'. The consolidated approach was intended to maintain NERC's focus on developing and retaining requirements that support the reliable operation of the Bulk-Power System (BPS).

The WEQ-023 standards drafted did not incorporate honoring neighboring systems nor ensure an entity have an ATCID, or TRMID, or CBMID because the thought was that it would be laid out in the NERC space under MOD-001-2. So NAESB would have to incorporate all of this into the business practice, which would blur the lines of reliability and commercial that the project was developed to address.

TVA agrees with the goal of the Standards Efficiency Review Team to decrease the number of requirements and make the standards less confusing and less burdensome. Yet, it is important that the standards still ensure a relatively consistent and reliable calculation of transfer capability. TVA feels the accurate calculation of transfer capability is a reliability issue. It is the job of the operations planners to give the operators a system that was planned to be reliable. If the operators are given a system that has numerous n-1 overloads planned into the system, then the operational planning engineers did not do their job. We do not want our operators to intentionally have to handle numerous TLRs and generation re-dispatch because of an oversold system. If the TOP and TSP oversell the system, it may be difficult for the operators to maintain system reliability. A transmission system constantly in TLR3 and TLR5 due to inaccurate calculations of transfer capability is a reliability issue and not just a commercial issue. If your neighbor is constantly selling transfer capability and ignoring the impact on your system, this too will affect your reliability. This does not just impact transmission costs as some would believe.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

Electric Reliability Council of Texas, Inc. (ERCOT) agrees with the recommendations and rationales to retire the following requirements identified in the Standard Authorization Request (SAR):

FAC-008-3 R7, R8

FAC-013-2 R1, R2, R4, R5, R6 (All)

INT-004-3.1 R1, R2, R3 (All)

NUC-001-3 R1

TOP-001-4 R19, R22

ERCOT does not oppose the recommendations to retire of the following requirements identified in the SAR, but does not necessarily agree with each rationale articulated in support of retirement:

BAL-005-1 R4, R6

COM-002-4 R2

EOP-005-3 R8

EOP-006-3 R7

FAC-003-4 R5, R6, R7

INT-006-4 R3.1, R4, R5

INT-009-2.1 R2

INT-010-2.1 R1, R2, R3 (All)

IRO-002-5 R1, R4, R6

IRO-006-5 R1

IRO-008-2 R6

IRO-014-3 R3

IRO-017 R3

MOD-001-1a R1, R2, R3, R4, R5, R6, R7, R8, R9 (All)

MOD-001-2 R1, R2, R3, R4, R5, R6 (All)

MOD-004-1 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12 (All)

MOD-008-1 R1, R2, R3, R4, R5 (All)

MOD-020-0 R1 (All)

MOD-028-2 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11 (All)

MOD-029-2a R1, R2, R3, R4, R5, R6, R7, R8 (All)

MOD-030-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10 (All)

PRC-004-5(i) R4

PRC-015-1 R1, R2, R3 (All)

PRC-018-1 R1, R2, R3, R4, R5, R6 (All)

TOP-001-4 R16, R17

VAR-001-4.2 R2, R3

VAR-001-4.2 E.A.15

ERCOT does not agree with the recommendation and rationale to retire the following requirement identified in the SAR for the reasons stated below:

PRC-019-2 R1

ERCOT does not support the retirement of PRC-019-2 Requirement R1 without revisions to Requirement R2. That's because Requirement R2 is triggered by "the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1 . . ." and requires "each Generator Owner and Transmission Owner . . . perform the coordination as described in Requirement R1." The outright retirement of Requirement R1, without revisions to Requirement R2 would result in problems applying Requirement R2. However, ERCOT does not oppose the spirit of the recommended retirement.

Likes 0	
Dislikes 0	

Response
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment
The SAR proposes retiring NERC Reliability Standards PRC-015-1 and PRC-018-1. We believe both standards are already scheduled to be retired based on existing implementation plans. According to the PRC-012-2 implementation plan (https://www.nerc.com/pa/Stand/Prjct201005_3RmdialActnSchmsPhase3ofPrtctnSystmsDL/PRC-012-2_Implementation_Plan_clean_04182016_final.pdf), PRC-015-1 will be retired December 31, 2021. In comparison, PRC-018-1 will be retired June 30, 2022, based on the PRC-002-2 implementation plan (https://www.nerc.com/pa/Stand/Project%20200711%20Disturbance%20Monitoring%20DL/2007-11_DM_Imp_Plan_2014Sep01_clean.pdf).

Likes 0	
Dislikes 0	

Response
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment
General comments: In light of the increasing maturity of the mandatory Reliability Standard compliance enforcement model in North America, Hydro-Québec TransÉnergie supports shifting the standard to a less prescriptive, more performance-based approach. Also, we support consolidation of requirements into a smaller, more efficient set of requirements. We consider important that the new versions of these standards have distinct numbers, whether that be a minor revision or a roman numeral. In particular, we do not support adding the phrase "(Retirement approved by FERC effective date)" as was done in the first round of the P81 retirements. Such an approach renders the version numbering useless and requires complex manipulation for jurisdictions that cannot delegate their versioning to NERC's website.

BAL-005-1 R4, R6.

We support the retirement.

COM-002-4 R2, EOP-005-3 R8, EOP-006-3 R7

We support the transfer of the requirements to PER-005-2. However, the PER-005-2 would have to be modified in order to prevent a possible gap.

Requirement 1.1 of the PER-005-2 Reliability Standard requires entities to identify “company-specific Real-time reliability-related tasks based on a defined and documented methodology”. Nothing in the text requires the methodology to include restoration tasks or three-way communication *per se*. The methodology itself is not subject to enforcement. To avoid creating a possible gap, the requirements for the methodology should be specified and include system restoration and three-way communications or the reference to the methodology should be removed.

We understand that an entity that does not include Blackstart or three-way communication in its methodology/list of tasks is not meeting the objective of the standard. In our view, shifting to a performance based standards approach isn't synonymous with leaving things implicit. Rather, it is about focusing on the objectives to be achieved. a phrase like "systematic training on all BES tasks relevant to the entity" would be more appropriate than references to a methodology, or specifying the objectives of the methodology.

FAC-003-4.

The argument that NERC Rules of Procedure allow for extenuating circumstances for natural disasters in order to reduce penalties seems an insufficient justification for the retirement of Requirement R5.

Also, the NERC Rules of Procedure are not necessarily in effect in Canadian jurisdictions. For example, Québec does not have the NERC Rules of Procedure in effect. If a requirement can be waived through a corrective action plan, it should be explicit in the standard, not in the rules of procedure.

For these reasons, R5 should be rewritten but not stripped out.

We support the retirement of R6 and R7 for the reasons given in the SAR.

FAC-008-3 R7, R8

The requirements are not entirely duplicative as described in the justification, since the TO function cannot obtain data requested through MOD-032, IRO-010 or TOP-003. However, we do not view the TO data request as essential to reliability. We therefore support the retirement of these two requirements.

FAC-013-2

We support the retirement of this standard. This standard does not support reliability in the Québec interconnection.

INT-004-3.1

We support the retirement of this standard because its only currently effective requirement, requirement R3, is duplicative, from a reliability perspective, with Requirement 2 of IRO-010-2 which includes coordination of pseudo-interconnections.

INT-006-4 R3.1, R4, R5; INT-009-2.1 R2; INT-010-2.1 R1, R3

We support the retirement of these requirements for the reasons given.

IRO-002-5 R1

We support the retirement of these requirement for the reasons given. Given the rationale applies also the R2, and that R3 is a control for R2, those two requirements should also be considered for consolidation and simplification, retaining only the redundancy requirement.

IRO-002-5 R4

We support the retirement of this requirement for the reason stated.

IRO-002-5 R6

Requirement 6 also requires “over a redundant infrastructure” which is not pre-supposed by the other requirements. This requirement could be consolidated with a stripped down version of R2 (as mentioned in comments for R1) in order to specify the redundancy requirements for monitoring and data exchange. However, the justification is inadequate to justify a retirement.

IRO-006-5 R1

The applicable entity in requirement R1 is the RC. IRO-001-4 R2 is not applicable to the RC function. As such, the justification in the SAR is incorrect. We had suggested in our initial filing that this requirement be consolidated in IRO-014.

IRO-008-2 R6

We consider letting impacted entities know that an emergency situation has finished is an operational requirement and not an administrative requirement. More broadly, Requirements 5 and 6 are implicit to the plans devised in R1, R2 and to requirement 3. In particular, notifying entities of problems and of the end of problems should be part of the plan. If necessary to specify it, it should be a performance requirement of the plan in R1, not two separate requirements. Therefore we support the retirement of R5 and R6, but not as currently justified.

IRO-014-3

We support the retirement.

IRO-017-1 R3

TPL-001-4 R8 requires an RC to request a Planning Assessment, whereas an affected RC is sent a Planning Assessment. The simple elimination of R3 could allow for a gap where an RC does not request a Planning Assessment that affects it and the Planner neglects to inform the affected party. R3 can easily be integrated into R8 (ie. “Each PC and TP shall distribute its PA results to adj. PC, adj. TP and any affected RC within 90 …”)

MOD-020-0 R1

MOD-020-1 allows operators (RC and TOP) to request information. In contrast, MOD-031-2 does not give RC or TOP the authority to request DSM information. IRO-010-2 does give the RC that authority but does not apply to the RP. So unless the NERC functional model guarantees that the DP has that information, there could be a gap.

PRC-004-5(i) R4

The structure of R4 has always been flawed. Is **a** exceeding the delay in R1 or R3 a non-compliance if actions are undertaken under R4? Implicitly the standard implies yes. In R1 and R3, there was no written possibility for “no cause was identified”. Removing R4 then makes not identifying a cause in R1 or R3 a non-compliance. So retiring R4 would require a change in monitoring interpretation. The proposed retirement is not without impact.

PRC-019-2 R1

R2 depends on the content in R1 and so R1 cannot be removed. Therefore, the text in R2 must be adjusted to remove the reference. We support the removal of the 5 year verification cycle in favor of the “upon modification” approach.

TOP-001-4 R16, R17, R19, R22

We support the retirement of these requirements.

MOD-xxx commercial retirements

We support the removal of commercial considerations from the MOD 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	

Southern Company does agree with the recommendations proposed for retirement, with the following exceptions:

- **MOD-001-2 R1 -** Southern does not believe that **MOD-001-2 R1** should be retired. However, the other requirements should be retired as they do not add any value to reliability. The overall purpose of this standard was to force marketers to coordinate with TSPs to prevent the overestimating of ATC and the overselling capacity which could create SOL/IROL exceedances during real time operations.

Although this is important, it's more commercial than for reliability as the RC and TOP already has an obligation under the current TOP and IRO standards to perform next day and real-time studies to identify any potential/actual exceedances in their respective areas. If any exceedances contributed to capacity overloading are identified, then the RC or TOP would be able to investigate and take any actions necessary (including directing the cutting of capacity on the overloaded facility) to relieve the SOL/IROL exceedance.

Although, it may be a good business practice to have these requirements in place from a commercial standpoint, they add no additional value to reliability as the anticipated result of SOL/IROL exceedances are already covered in other enforceable standards.

- **PRC-019-2 R1:** Southern Company believes **PRC-019-2 R1** can not be retired without modifying PRC-019-1 R2 to remove the reference to PRC-019-2 R1. The team should consider moving this requirement to Phase 2 of this Project.

Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	
Comment	

Seattle City Light would like to thank the three SER teams who worked very hard and we look forward to the second Phase of this project for further refinement of the other standards that could benefit from consolidation or modification with other possible retirements. We agree with all the retirements identified in the proposed SAR except for the recommended changes to FAC-003 as follows:

City Light supports the abrogation of R5 and R7. We agree that satisfying R1 and R2 makes R5-R7 technically redundant assuming entities have a good program. However, we believe Requirement 6 (annual inspections of applicable transmisison lines) should be kept as a minimum, as it forces a level of direct oversight that benefits the industry. Remote sensing technology is/has been advancing at a rate that makes these inspections far more practical than they have ever been, and would allow Regulators a high level of assurance as well as providing utitliy managers with the regulatory incentive to support a fail-safe measure that might otherwise not be funded in tight financial times, without overly burdening entity budgets.

Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The NSRF would like to thank the SER review team for their speed and professionalism in identifying the applicable Requirements for retirement.	
Likes 0	
Dislikes 0	
Response	
Patti Metro - National Rural Electric Cooperative Association - 3,4	
Answer	Yes
Document Name	
Comment	
NRECA with concurrence of its member Reliability advisors agree with the recommendations and rationales for retirement of the proposed requirements. In our review, we assumed that drafting teams will develop detailed technical justifications for the proposed retirements that will be used in the associated filings to FERC for said retirements.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

Jeff Kimbell - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
We appreciate the effort and results from the Standards Efficency Review Teams in determining requiremetns that should be retired, or at least modified.	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Tri-State agrees with the recommended retirements. However, we would like to know what the process of retiring these requirements will be. We would specifically like to know how requirements that are not yet in effect will be handled, if they were to go into effect before this project is completed.	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Reclamation supports the proposed retirement of the listed requirements.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Hydro One	
Answer	Yes

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

Texas RE appreciates the SER teams' review of the Reliability Standards in order to improve efficiency. Texas does, however, have some concerns with the proposed retirements, indicated below.

- Training: While PER-005-2 does include a requirement to train personnel on Real-time reliability-related tasks, it puts the burden on responsible entities to determine what those reliability-related tasks are. Texas RE is concerned that without the specific training provisions in COM-002-4 R2, EOP-005-3 R8, and EOP-006-3 R7, reponsbile entities will not be trained on those aspects. Rather than eliminate those requriements, Texas RE recommends revising PER-005-2 to include the specific trainings identified in COM-002-4 R2, EOP-005-3 R8, and EOP-006-3 R7.

- FAC-003-4 R6, R7: Requirements R6 and R7 include an annual requirement for vegetation management, while Requirements R1 and R2 do not. Texas RE recommends not retiring Requirements R6 and R7 as annual inspections and implementation of the vegetation work plan are measureable requirements that address preventive measures to avoid vegetation encroachment. In addition, the ERO Enterprise has acknowledged that there has been an uptick in FAC-003 noncompliance and this recommendation appears to ignore those challenges.

- FAC-008-3 R7, R8: Due to the importance of the use of accurate Facility Ratings in reliable BES operations and planning, it is recommended that FAC-008-3 Requirements R7 and R8 remain effective in order to emphasize the need to provide accurate Facility Ratings to entities that require Facility Rating data. These Requirements place an emphasis on the provision of accurate Facility Ratings to the entities responsible for the operation and planning of the BES. Although IRO-010 and MOD-032 data specifications will likely address the provision of Facility Ratings to the these entities, the large quantity of additional data potentially included within the data specifications can lead to a reduced emphasis on the Facility Rating component of the data specification.

- IRO-002-5 R6: Texas RE is concerned that retiring IRO-002-5 Requirement R6 would remove the emphasis on how registered entities should use alarming tools.

- IRO-008-2 R6: Texas RE is concerned with eliminating this requirement, there would be no explicit requirement for the RC to notify impacted TOPs and BAs when there could be a SOL or IROL. This is something the Operating Plan should have, but with no specific requirement, there is a chance not all Operating Plans will have this provision.

- IRO-014-3 R3: Requirement R1 does require development and implementation of Operating Procedures, Operating Processes, or Operating Plans for activities that require notification or coordination of actions that may impact adjacent RC Ares. Parts 1.1 – 1.5 address items that must be included. However, this does not ensure that all potential Emergencies are addressed within the Operating Procedures, Operating Processes, or Operating Plans. IRO-014-3 is still needed to ensure that appropriate coordination and communication happens when an actual or expected Emergency is identified by the RC. If the SER team would like to retire IRO-014-3 Requirement R3, the provision for Emergencies could be captured in Requirement R1.

- PRC-019-2 R1: Requirement R2 is dependent on the initial coordination required by Requirement R1 and does not address new generating units. If Requirement R1 is retired, there would be no initial coordination required for new units. Addtionally, there would be no initial baseline to determine whether there is a coordination issue.

- IRO-002-5 R4, TOP-001-4 R16, R17: Texas RE is concerned that without this requirement, System Operators would not have the authority to approve outages. Prior to this Requirement being in place, a System Operator would not have approved outages of monitoring tools. Texas RE is concerned if this requirement is removed, System Operators may not have the authority to approve outages. Texas RE notes this was a recommendation in the 2013 Independent Review Experts Review Project report.

- IRO-017-1 R3: This Requirement is written for the TP and PC to explicitly provide the impacted RC a Planning Assessment whereas TPL-001-4 Requirement R8 relies on actions by the RC to submit a written request. Coordination and communication are building blocks for reliably operating a grid. TPL-001-4 Requirement R8 has no explicit requirement to notify an RC that an Assessment is completed and inserts a timeframe for response to the RC who may not even know that a Planning Assessment has been completed that requires their awareness. This introduces a reliability gap by removing the explicit provision requirement. Furthermore, determining what a “reliability related need” is seems to be a challenge for entities not willing to provide communication and has been implemented in various disparate ways for Requirements with this language.

- PRC-004-5(i) R4: Indeterminate causes of misoperations are difficult issues that can provide valuable lessons for all entities involved in system protection. Protection System misoperations continue to be a significant reliability risk factor and exacerbate the impact of transmission outages. In the 2017 State of Reliability Report 9% of the misoperations were categorized as “Unknown/Unexplainable” . The 2018 State of Reliability Report noted that “Protection system misoperation should remain an area of focus, as it continues to be one of the largest contributors to the severity of transmission outages.” The 2018 State of Reliability report shows no decline in the percentage (9%) which is indicative that more focus is needed. Tracking the issues, if actively pursued, may help entities across the ERO understand complex issues when the cause of a misoperation is identified.

- PRC-018-1: Texas RE recognizes there are parts of this standard that are problematic. However, the purpose of the standard is to monitor disturbance data and learn about events that occur in order to prevent them from happening again. To do this registered entities need to adequately measure quantifiable aspects of the event (e.g., current, voltage, frequency) on the same timelines (i.e. time synchronized). This is an important aspect of reliability. Rather than retire the standard completely, Texas RE suggests correcting the references to a non-FERC approved Standard and vague language.

- VAR-001-4.2 R2, R3 Both requirements depend upon an entity's interpretation of an SOL. These Requirements at least give specific actions for entities to follow and support the 2003 Blackout Report Recommendation 23.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	
Document Name	

Comment

INT-004-3.1 Requirement R1, Requirement R2, Requirement R3

We support the retirement of these requirements.

INT-006-4 Requirement R3 Part 3.1, Requirement R4, and Requirement R5

We support the retirement of requirements INT-006-4 Requirement R3 Part 3.1, Requirement R4, and Requirement R5. However, we do question the rationale implying that the NAESB e-Tagging Specification is FERC approved. The NAESB e-Tagging Specification is not submitted to FERC for approval and is not the same as a FERC approved requirement be it NERC or NAESB. Additionally, some entities who are non-FERC jurisdictional are not required to follow the NAESB standards, so the likelihood of a current NERC requirement not being met is greater when it is moved to a NAESB specification. The Standards Efficiency Review teams should be aware of this concern before they delete it outright.

INT-010-2.1 Requirement R1, Requirement R2, and Requirement R3

We are concerned that the removal of INT010-2.1 removes the ability for an RC to direct a change to the interface flow before an Arranged Interchange is approved under the INT-006 Standard. Removal of INT-010-2.1 and the reference in INT-009-2.1 creates an issue with the requirement to submit tags, after the fact, for reliability adjusted Confirmed Interchanges and those that are required for reliability reasons such as emergency. Additionally, any cgppd,hanges to INT010-2.1 R1 should be coordinated with NAESB. NAESB Business Practice Standard WEQ-004-1.7 specifically references INT010-2.1 R1. California ISO and ERCOT have not signed on to these comments.

FAC-013-2 (All requirements)

We are concerned with the proposed retirement of FAC-013-2, which has been helpful in requiring Planning Coordinators do transfer capability analysis and assessment. The transfer assessment in FAC-013 will actually be the only “transfer capability assessment” after retiring FAC-010.

PRC-004-5(i)

Tracking investigative actions related to relay misoperations - Misoperations causes vary and the investigation of each unique event will provide any reliability benefit – not the continuous tracking of the investigation itself. Support deletion.

PRC-015-1, R1, R2, R3

PRC-015-1 is superseded by PRC-012-2

Maintain a list of RAS is administrative in nature and does not provide any operational or engineering benefit to ensure reliability. NERC also has authority under Rule 1600 to require registered entities to provide a list of RAS if needed – support deletion

PRC-018-1 R1, 2,3,4,5,6

Ensure DME's as required by PRC-002-1 meet specific criteria.

FERC approved PRC-018 assuming RROs enforce it through regional DME programs – most RROs have retired their programs

The basis for this retirement seems to be based on a lack of a need for a single standard for DME installations. Technology has evolved where DMEs can be readily available at nearly every breaker station. Support deletion.

PRC-019-2 R1

R2 already requires 90 day coordination for changes impacting voltage regulation settings. R1 is a 5 year requirement, making it a redundant requirement. Support deletion.

IRO-006-5

Retiring IRO-006-5 may leave an unintended gap in the requirements. The SAR justifies retirement of IRO-006-5 based on redundancy with R2 of IRO-001-4; however, the requirements for IRO-006-5 and IRO-001-4 R2 are structured to be mutually exclusive and satisfy different purposes.

"Each Interconnection has its own TLR procedure within the NERC Reliability Standards. If an entity cannot respond to the RC's request it can notify them in accordance with IRO-001-4 R2. Therefore,

IRO-006-5 R1 is redundant and unnecessary."

IRO-001-4 R2 is narrowly drawn to require the applicable functional entity to comply with ***"its Reliability Coordinator's Operating Instructions…(emphasis added)"*** and implies an operating instruction existing within a single interconnection; whereas IRO-006-5 is intended to apply more generally to interchange transactions from any [Reliability Coordinator] in another Interconnection (emphasis added)" and is across interconnection boundaries.

As IRO-001-4 R2 and IRO-006-5 each applies to separately defined purposes, retiring IRO-006-5 without mitigating this discrepancy may create an unanticipated gap that cannot be satisfied by current IRO-001-4 R2.

IRO-006 R1 covers both curtailment of transactions within an Interconnection and those across Interconnections. While IRO-001-4 may arguably cover those in the former case, it does not cover those in the latter case. Hence, retiring IRO-006 will leave a reliability gap for curtailing transactions crossing Interconnection boundaries. The SRC generally supports the other proposed retirements presented by the SER Team.

Likes 0	
Dislikes 0	

Response

2. Are there any additional requirements that you contend could be retired without modifying any other requirement(s) and/or standard(s)? If so, please state the standard(s) and requirement number(s) in your response(s) along with your rationale(s) for retiring the requirement(s).

Wendy Center - U.S. Bureau of Reclamation - 1,5

Answer	No
Document Name	

Comment

Not at this time.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5 - WECC

Answer	No
Document Name	

Comment

FAC-003-4 R1/R2

Rationale:

BC Hydro acknowledges the SER Team efforts to review and analyze the NERC Standards and offers the following for consideration in Phase 2 of this project.

R1 and R2 of FAC-003-4 are essentially the same requirement (with the only distinction that R1 addresses applicable lines that are identified as an element of an IROL or part of a Major WECC Transfer Path, while R2 addresses all other applicable facilities subject to this NERC standard) and have the same Violation Risk Factor (VRF).

When FAC-003-2/3 was initially drafted, R1 and R2 had different proposed VRFs. However, when finally approved they both ended up with a VRF of "High". It then seems redundant to continue with both requirements as they essentially require collection of the same evidence to demonstrate compliance and the risk is deemed the same regardless of whether an applicable line is part of an IROL/WECC transfer path or not.

Therefore, BC Hydro recommends that R1 and R2 be consolidated into one single requirement.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Hydro One	
Answer	No
Document Name	
Comment	
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	
Likes 0	

Dislikes 0	
Response	
Shivaz Chopra - New York Power Authority - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Harward - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kelsi Rigby - APS - Arizona Public Service Co. - 1,3,5,6

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruth Miller - Exelon - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Puscas - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	

We understand that this first phase is just for simple retirements that do not require changes to requirements or consolidation of requirements. We consider that there is considerable opportunity for consolidation of requirements in the NERC reliability standards and look forward to commenting on those as well when that phase is undertaken.

We consider that event reporting (EOP-004-4 R2) within 24 hours is not a reliability issue *per se*. Event reporting, event analysis and event response are key reliability activities, but the reporting of events within 24 hours is an arbitrary administrative activity that does not contribute to reliability. If this requirement cannot be retired, then we submit that it should be modified in a future review.

EOP-011 R4

Implicit to R1 and R2 that state that the respective plan must be reviewed and 3.1.3 that states that the RC must give the plan back with comments for fixes and deadlines. If the entity does not revise its plan in the delay given by the RC, then the plan in effect is no longer RC reviewed. Therefore, R4 could be retired.

IRO-014 R5 and R6

These requirements should be retired, rewritten or consolidated with other requirements.

Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	

Comment	

1. We believe the SAR should include the coordination of this project's efforts with other NERC development projects, such as Project 2015-09 Establish and Communicate System Operating Limits, Project 2017-07 Standards Alignment with Registration, and the 2018 Periodic Standards Grading Review. We have found it difficult to identify which project will retire specific Reliability Requirements and direct our comments to the appropriate SDT accordingly. We also question why a consideration of comments document was not generated in response to all the matrices submitted. Several of our suggestions identified in a matrix that we submitted on February 2, 2018, were not incorporated into this SAR.
2. Documentation regarding Phase 2 of this project is vague. Will the CIP requirements be incorporated in the next phase? Will all the training-related requirements be relocated to the PER standard family? Will requirements with inappropriate VRFs or inadequate VSLs be reviewed? Will requirements with excessive evidence retention periods be evaluated? We believe certain efficiencies could be gained following a review of all these requirements.
3. We believe Requirement R1 of COM-002-4 should be included in the SAR. The requirement identifies a minimum criteria set to include within a communications protocol that would be better suited in a Reliability Guideline, Implementation Guidance, or human-performance white paper. This criteria is already implied through other NERC Reliability Requirements addressing the issuance and response to Operating Instructions. The obligation is on the Operating Instruction issuer to ensure effective communication is used when soliciting a desired response and appropriate actions executed by the recipient.
4. There are no requirements from NERC Reliability Standard PRC-002-2 identified within the SAR. The purpose of that standard is to identify data collection device technical specifications and locations to place such devices to record information that can be reused for post-event analyses. We feel a better mechanism to inform industry of this information is through a Reliability Guideline.
5. We question why the SAR does not identify any requirements from NERC Reliability Standard PRC-027-1. The purpose of that standard is to coordinate Protection Systems installed to detect and isolate Faults on BES Elements. Although retroactively, similar coordination is found in NERC Reliability Standard PRC -004 based on potential risks to the BES, we believe the applicability of NERC Reliability Standard PRC-027-1 should be modified to focus on BES Facilities that operate at or above 200 kV, similar to the criteria identified within NERC Reliability Standard PRC-023-4.
6. We ask when NERC Reliability Standard EOP-004-4 will be aligned with the US DOE OE-417 Event Reporting Process. Any reporting criteria, including threshold and timing response for reporting an event, should be incorporated within a Reliability Guideline that aligns with the DOE process.
7. There are no requirements from NERC Reliability Standard EOP-008-2 included within this SAR. We question why requirements R5, R7, and R8 were not included, as Requirement R1 of the standard obligates the applicable entity to maintain a current copy of its Operating Plan. An applicable entity will already have internal maintenance controls in place, through its business continuity plan, that outline a review periodicity and testing frequency, both of which are likely to occur more frequently than once a year.
8. We thank you for this opportunity to provide these comments.

Likes 0	
Dislikes 0	

Response

Gregory Campoli - New York Independent System Operator - 2, Group Name ISO/RTO Standards Review Committee

Answer	Yes
Document Name	

Comment

INT-011-1.1

We also recommend as part of the Standards Efficiency Review initiative that INT011-1.1 be formally retired. We understand the standard is listed as inactive. However, it is still a FERC approved standard.

Likes 0	
Dislikes 0	

Response

Teresa Cantwell - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance

Answer	Yes
Document Name	

Comment

Incorrect response...please correct to reflect "No" on behalf of LCRA Compliance. ~Thank you!

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Florida Municipal Power Agency - 3,4,5,6 - FRCC, Group Name FMPA

Answer	Yes
Document Name	

Comment

COM-001-3

FMPA recommends COM-001-3 for retirement due to the fact having a phone and communication with other entities is an obvious business and operational need that should not need a NERC Standard Requirement. It is also redundant as requirements such as TOP-001-4 R3, R4, R5, R6 imply having a means to communicate with other entities. The amount of time an effort to prove from a compliance standpoint that an entity has a phone is burdensome. This purely administrative requirement does nothing to maintain or improve the reliability of the BES.

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

PRC-023-4 (R5): Duke Energy renews its assertion that R5 of PRC-023-4 should be retired. This requirement has no bearing on the reliability of the BES.	
Likes 0	
Dislikes 0	
Response	
Jeff Kimbell - Public Utility District No. 1 of Chelan County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
TOP-002-4 R4: The data gathered in accordance with this requirement is not needed to perform a reliable daily assessment and is not used in the study process except to fulfill this requirement. Specifically, this data is only applicable to the area within the BA. In performing a study, the model is set up with quantities reflecting the entire system (expected max plant outputs, total system load) so as to mirror reality rather than the small area just within the BA. TOP-010-1(i) R1, R2 & R3: The basis to address the quality and/or analysis functions of Real-time data is necessary when performing the Real-time Assessment that is required in TOP-001 R13. It seems duplicative to have a mandatory standard requiring data quality when that is a fundamental responsibility for the entity to ensure that Real-time Assessment results are valid and of good quality to ensure reliability. Consider retiring. TOP-010-1(i) R4: Real-time monitoring is essential for System Operator awareness to conduct Real-Time Contingency Analysis to meet TOP-001 R13. Consider retiring.	
Likes 0	
Dislikes 0	
Response	
Tara Lightner - Sunflower Electric Power Corporation - 1 - MRO	
Answer	Yes
Document Name	
Comment	
Also recommend removing FAC-008-3 R1 and R2 because: 1. Electrical Facility Ratings of generating stations have little value in maintaining reliability. 2. Real Power capability values do provide a reliability benefit, and this is covered by MOD-025.	
Likes 0	
Dislikes 0	

Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 5,6	
Answer	Yes
Document Name	
Comment	

TAPS and NCPA appreciate the work of the Standard Drafting Teams in developing this SAR. We believe the justifications for the SAR's proposed retirements are well-explained. We also believe, however, that several additional requirements should be retired, as set forth below.

COM-001-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12, and R13 (ALL)

Basic functionality. This should be part of the certification process for BAs, TOPs and RCs. For all other entities (DPs and GOs), it is not necessary to require communication to be proven as the RC, TOP or BA will assure that they can make contact with these entities, and all entities have internal and external Interpersonal Communications Capabilities. This Standard basically states to have primary and back up communications (a phone). In today's world, basic, daily functionality necessitates multiple avenues of communications such as a land line phone, a cell phone, text messaging, a radio, satellite phone, etc. This Standard is not necessary for reliability; it only enforces a compliance "gotcha" if a registered entity's primary communication system fails. There is not a reliability benefit from COM-001-3, just administrative burden. Communications are a basic function of every registered entity. The entire Standard should be retired.

COM-002-4 R3

R1 protocols cover all aspects of operating protocols. If communication is a reliability-related task, then training is covered in PER-005.

COM-002-4 R4

R4 and its subrequirements are a control and should not be an auditable item.

COM-002-4 R5, R6, R7

There should be no difference between an Operation Instruction under normal conditions and under Emergency conditions. R1 covers all Operating instructions. By imposing additional requirements on Operating Instructions that are issued during an emergency, R5, R6, and R7 make it necessary for entities to track whether each Operating Instruction was issued during an Emergency or during normal operations, in order to be able to demonstrate compliance. This administrative burden does not enhance reliability.

EOP-005-3 R3

Verify through NERC Certification program.

EOP-008-2 R2

Verify through NERC Certification program.

EOP-008-2 R3, R4

NERC Certified Operators can be addressed through Certification Program. R6 addresses Primary and Backup and can also address the sub-bullets in this Requirement. Sub-bullets of R4 can be addressed in R8.

EOP-010-1 R2

This is for situational awareness only and may be a mitigating feature of R1. If one K warning is not sent out, it becomes a non-compliance issue. This is also covered in EOP-011-1, R1.2.1.

EOP-010-1 R3.1

R3.1 is contained in R1. Per part 3.1, this will force the TOP to prove a negative if they did not receive any space weather information. Part 3.2 starts the mitigating processes for GMD events and part 3.3 concludes them. Part 3.1 is administrative in nature as alone, it does not accomplish anything; parts 3.2 and 3.3 mitigate the GMD. Recommend part 3.1 be retired. If not retired, part 3.1 should be modified to clearly state in the requirements or measures that proof of compliance is to show the steps only and entities are not required to prove a null set of data.

EOP-011-1 R1 subparts

R1.1 does not enhance or enforce reliability; it is only an auditable item. R1.2.2, R1.2.3, R1.2.4, R1.2.5, and R1.2.6 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan, only. R1 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R2 subparts

R2.1 does not enhance or enforce reliability; it is only an auditable item. R2.2.3 and its parts and R2.2.4, R2.2.5, R2.2.6, R2.2.7, R2.2.8 and R2.2.9 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan. R2 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R4

This is common sense. We do not need a Requirement to state that we have a specific time to update something issued by the RC. The RC can simply state have an update back by a certain time. This becomes a time “gotcha” issue during an audit or self report. This does not support system reliability.

EOP-011-1 R5

This is in line with the justification for retiring R4, as this is also common sense. The RC will act immediately on all emergency notifications. The time frame of 30 minutes only become an auditable point and does not support reliability. If the requirement is not retired, at minimum the 30 minute criterion should be deleted.

EOP-011-1 R6

This is clearly stated in the Functional model under Real Time actions and does not need to be contained here; the RC will act immediately on all emergency notifications. Recommend retirement of this Requirement.

FAC-002-2 R2, R3, R4, R5

Inherent in R1.

FAC-003-4 R4

R4 is a notification process only, without the next step of clearing happening. This alone does not support reliability. The clearing of the encroaching vegetation does support reliability and is covered in R1, R2, and R6.

FAC-008-3 R1, R2, R3, R6

Generator Facility Ratings are not useful as they are often different from the capability determined through MOD-025. This Standard is usually based solely on the nameplate ratings of components that are covered by this Standard. Nameplate ratings become irrelevant with MOD-025-2, which captures the true capabilities of the asset. The TP will be notified of MOD-025-2 findings. If the RC wants to know the MOD-025-2 capabilities, then they can ask for it under IRO-010-2 [*****This is the argument we made in our initial proposal, but the SDT is proposing to retire IRO-010-2 (though they're also relying in part on IRO-010-2 to support retiring FAC-008 R7 and R8, among others, so maybe we can do the same); are there other standards under which the RC can request information? Does the RC need to know MOD-025 information?**]. The TOP can also request the same information under TOP-003-3.

IRO-001-4 R1

This is the basic functionality of an RC, as outlined in the Functional Model.

IRO-001-4 R2

Per the Functional Model, the BA, TOP, and GOP have reliability interactions with the RC, hence supporting a secure and stable reliable system. The DP does not receive instructions from the RC; rather, they receive information from the BA and TOP.

IRO-001-4 R3

This does not need to be a Requirement. The RC can simply ask whether the registered entity has the ability to accomplish the task. If the entity can't, the RC will take alternate actions.

IRO-002-5 R3

Requirement 2 already provides for two active paths. A NERC certification program can ensure that the paths are being used periodically.

IRO-008-2 R3

The RC's performance of the analysis is identified in R1. A separately enforceable requirement that the RC take the common-sense action of informing impacted entities is unnecessary.

IRO-008-2 R4

IRO-018-1 R2, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc) without a hard standard-based 30 minute compliance threshold. Candidate for NERC certification program.

IRO-008-2 R5

This requirement supports R2 and process can be verified through NERC Certification (process review).

IRO-010-2 R3

Real time data transmission involves telemetry for thousands of points scanned or updated every few seconds. Retaining evidence of providing this volume of data is burdensome.

MOD-033-1 R2

This requires demonstration of the negative and after the fact validation. This should be part of the Event Analysis process and not a NERC Requirement.

NUC-001-3 R9

Requirement is administrative as it only specifies what must be in the agreement. R9 can be moved to a Guidance document since R9's second bullet states "The Nuclear Plant Generator Operator and the Transmission Entity are responsible for ensuring all the R9 elements are addressed." An item can be addressed by stating that it is not applicable for the entity.

PER-003-1 R1, R2, R3 (ALL)

This Requirement is predicated on the NERC exam which is the responsibility of NERC and the PCGC, not a Registered Entity. Recommend this Standard be retired. Operators are trained on competencies. Competencies can be verified through the training Standards. Certifications should be verified through the NERC Certification program.

PER-004-2 R1

In addition to being redundant with PER-003-1 (which we also recommend be retired), this requirement is part of the Certification process and does not need to be within a Standard.

PER-004-2 R2

Already covered by IRO-009 R1/R2.

PER-005-2 R5, R6

Operations Support Personnel know their impact on reliability and the task list. The prep and training used for OSP and the trainers is better spent for their job duties in support of reliability.

PRC-002-2 R1-R12 (ALL)

Disturbance monitoring is for post-event analysis and does not have direct impact on reliability. Guidelines and best business practices are sufficient to help improve accuracy and coordination. This very granular and prescriptive standard is not needed.

PRC-004-5(i) R2, R3, R5

Only R1 and R6 are required in order to support system reliability and stability. This Standard has too many time frames within each requirement and only provides a compliance gotcha if not followed. Time frames don't support reliability. The intent of this Standard is if you have a mis-operation that you notify everyone involved and fix it so it (hopefully) doesn't happen again.

PRC-005-6 R5

For PRC-005 Unresolved Maintenance Items (UMIs) are a low-volume and low-risk population with little to zero proven actual risk. We are not aware of any events where UMIs were cited as a primary or contributory cause to a BES outage in the Events Analysis program. Given the low volume of actual documented risk impacts and the low volume of self-logs or spreadsheet Notice of Penalty (SNOPs and NOPs), the UMI definition and requirement should be retired. If not retired, the UMIs should be modified to clearly state in the requirements or measures that compliance by exception is allowed and that regulated entities are not required to prove a null set of data.

TOP-001-4 R1

The basic functionality of a TOP is to operate or direct operation of equipment to maintain reliability. COM-002-4 clearly indicates that the TOP will be using Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R2, R4-R7

Please see responses re IRO-001-4 for retirement justification.

TOP-001-4 R3

Requirement language is poorly worded because it is not specifically tied to Operating Instructions *issued under TOP-001-4 R1* (i.e., Operating Instructions issued to maintain reliability). As such, every entity in R3 must maintain a list of every Operating Instruction issued or received, whether the OI was issued for reliability or not. The NERC Glossary of Terms definition for Operating Instruction pulls in all orders given to others to change the state of a BES Element, which means all planned switching orders issued by the operator, not just OIs issued for reliability. This requirement would be improved by both limiting the duration Operating Instruction evidence needs to be retained and clarifying that the requirement applies only to OIs from TOP-001-4 R1. The RSAW for TOP-001-4 R3 must also be corrected because it directs the audit to begin with the list of "all" Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R8

Covered by EOP-011 R5 or can be merged with same Requirement. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R9

EMS quality codes suffice for notifications of RTU outages and were accepted by the RRO. However, the Regional Entity does not agree. So now unplanned outages need to be tracked for 30 minute overages for reporting. This detracts from reliability and does not enhance reliability, especially when these outages are already indicated by quality codes. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R13

TOP-010-1 R3, when implemented, will address RTA quality. The quality process could also assure RTA activity in accordance with utility practice (RTA, RTA backup, etc.) without a hard Requirement-based 30-minute compliance threshold. Candidate for NERC Certification program.

TOP-001-4 R21

R20 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-001-4 R24

R23 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-002-4 R3

The TOP's performance of the analysis is required by R1. A separately enforceable requirement that the TOP take the common-sense action of informing impacted entities is unnecessary. Could be verified through NERC certification.

TOP-002-4 R4, R5, and R7

Daily Operating Plans are not needed for BAs. Generation dispatch information can be gathered and shared through data provision requirements.

TPL-007-1 R1

Administrative.

VAR-001-4.1 R1

Duplicative of FAC-014.

VAR-001-4.2 R5

All of R5 appears to be administrative and a common-sense operations item. All entities keep impedance and tap information on their transformers. There isn't any reason to withhold information if requested, so a mandatory standard backed by sanctions to provide information within 30 days is simply an administrative clock. It's wasteful of both entity and regulator resources.

VAR-002-4.1 R3

Duplicative of other standards requiring data provision. There is no justification for the 30 minute timing requirement; if a timing requirement is retained, it is not a good reliability practice to require notification "within 30 minutes," but only if status is not restored within 30 minutes.

VAR-002-4.1 R4

Duplicative of other standards requiring data provision. There is no justification for a 30 minute time limit and this becomes a compliance trap.

VAR-002-4.1 R5

Duplicative of other standards requiring data provision.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 5,6

Answer	Yes
Document Name	

Comment

TAPS appreciates the work of the Standard Drafting Teams in developing this SAR. We believe the justifications for the SAR’s proposed retirements are well-explained. We also believe, however, that several additional requirements should be retired, as set forth below.

COM-001-3 R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12, and R13 (ALL)

Basic functionality. This should be part of the certification process for BAs, TOPs and RCs. For all other entities (DPs and GOs), it is not necessary to require communication to be proven as the RC, TOP or BA will assure that they can make contact with these entities, and all entities have internal and external Interpersonal Communications Capabilities. This Standard basically states to have primary and back up communications (a phone). In today's world, basic, daily functionality necessitates multiple avenues of communications such as a land line phone, a cell phone, text messaging, a radio, satellite phone, etc. This Standard is not necessary for reliability; it only enforces a compliance “gotcha” if a registered entity’s primary communication system fails. There is not a reliability benefit from COM-001-3, just administrative burden. Communications are a basic function of every registered entity. The entire Standard should be retired.

COM-002-4 R3

R1 protocols cover all aspects of operating protocols. If communication is a reliability-related task, then training is covered in PER-005.

COM-002-4 R4

R4 and its subrequirements are a control and should not be an auditable item.

COM-002-4 R5, R6, R7

There should be no difference between an Operation Instruction under normal conditions and under Emergency conditions. R1 covers all Operating instructions. By imposing additional requirements on Operating Instructions that are issued during an emergency, R5, R6, and R7 make it necessary for entities to track whether each Operating Instruction was issued during an Emergency or during normal operations, in order to be able to demonstrate compliance. This administrative burden does not enhance reliability.

EOP-005-3 R3

Verify through NERC Certification program.

EOP-008-2 R2

Verify through NERC Certification program.

EOP-008-2 R3, R4

NERC Certified Operators can be addressed through Certification Program. R6 addresses Primary and Backup and can also address the sub-bullets in this Requirement. Sub-bullets of R4 can be addressed in R8.

EOP-010-1 R2

This is for situational awareness only and may be a mitigating feature of R1. If one K warning is not sent out, it becomes a non-compliance issue. This is also covered in EOP-011-1, R1.2.1.

EOP-010-1 R3.1

R3.1 is contained in R1. Per part 3.1, this will force the TOP to prove a negative if they did not receive any space weather information. Part 3.2 starts the mitigating processes for GMD events and part 3.3 concludes them. Part 3.1 is administrative in nature as alone, it does not accomplish anything; parts 3.2 and 3.3 mitigate the GMD. Recommend part 3.1 be retired. If not retired, part 3.1 should be modified to clearly state in the requirements or measures that proof of compliance is to show the steps only and entities are not required to prove a null set of data.

EOP-011-1 R1 subparts

R1.1 does not enhance or enforce reliability; it is only an auditable item. R1.2.2, R1.2.3, R1.2.4, R1.2.5, and R1.2.6 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan, only. R1 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R2 subparts

R2.1 does not enhance or enforce reliability; it is only an auditable item. R2.2.3 and its parts and R2.2.4, R2.2.5, R2.2.6, R2.2.7, R2.2.8 and R2.2.9 are all actions or event types that require actions. These are all event-specific. The Operating plan will just say that the operator will do something to mitigate these events. Then it becomes an auditable item in the Operating Plan. R2 is simple enough: have a plan for emergencies. Recommend subcomponents be retired.

EOP-011-1 R4

This is common sense. We do not need a Requirement to state that we have a specific time to update something issued by the RC. The RC can simply state have an update back by a certain time. This becomes a time “gotcha” issue during an audit or self report. This does not support system reliability.

EOP-011-1 R5

This is in line with the justification for retiring R4, as this is also common sense. The RC will act immediately on all emergency notifications. The time frame of 30 minutes only become an auditable point and does not support reliability. If the requirement is not retired, at minimum the 30 minute criterion should be deleted.

EOP-011-1 R6

This is clearly stated in the Functional model under Real Time actions and does not need to be contained here; the RC will act immediately on all emergency notifications. Recommend retirement of this Requirement.

FAC-002-2 R2, R3, R4, R5

Inherent in R1.

FAC-003-4 R4

R4 is a notification process only, without the next step of clearing happening. This alone does not support reliability. The clearing of the encroaching vegetation does support reliability and is covered in R1, R2, and R6.

FAC-008-3 R1, R2, R3, R6

Generator Facility Ratings are not useful as they are often different from the capability determined through MOD-025. This Standard is usually based solely on the nameplate ratings of components that are covered by this Standard. Nameplate ratings become irrelevant with MOD-025-2, which captures the true capabilities of the asset. The TP will be notified of MOD-025-2 findings. If the RC wants to know the MOD-025-2 capabilities, then they can ask for it under IRO-010-2 [*****This is the argument we made in our initial proposal, but the SDT is proposing to retire IRO-010-2 (though they’re also relying in part on IRO-010-2 to support retiring FAC-008 R7 and R8, among others, so maybe we can do the same); are there other standards under which the RC can request information? Does the RC need to know MOD-025 information?**]. The TOP can also request the same information under TOP-003-3.

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PER-003-1 R1, R2, R3 (ALL)

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PER-004-2 R1

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PER-004-2 R2

Already covered by IRO-009 R1/R2.

PER-005-2 R5, R6

Operations Support Personnel know their impact on reliability and the task list. The prep and training used for OSP and the trainers is better spent for their job duties in support of reliability.

PRC-002-2 R1-R12 (ALL)

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The basic functionality of a TOP is to operate or direct operation of equipment to maintain reliability. COM-002-4 clearly indicates that the TOP will be using Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R2, R4-R7

Please see responses re IRO-001-4 for retirement justification.

TOP-001-4 R3

Requirement language is poorly worded because it is not specifically tied to Operating Instructions *issued under TOP-001-4 R1* (i.e., Operating Instructions issued to maintain reliability). As such, every entity in R3 must maintain a list of every Operating Instruction issued or received, whether the OI was issued for reliability or not. The NERC Glossary of Terms definition for Operating Instruction pulls in all orders given to others to change the state of a BES Element, which means all planned switching orders issued by the operator, not just OIs issued for reliability. This requirement would be improved by both limiting the duration Operating Instruction evidence needs to be retained and clarifying that the requirement applies only to OIs from TOP-001-4 R1. The RSAW for TOP-001-4 R3 must also be corrected because it directs the audit to begin with the list of "all" Operating Instructions. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R8

Covered by EOP-011 R5 or can be merged with same Requirement. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R9

EMS quality codes suffice for notifications of RTU outages and were accepted by the RRO. However, the Regional Entity does not agree. So now unplanned outages need to be tracked for 30 minute overages for reporting. This detracts from reliability and does not enhance reliability, especially when these outages are already indicated by quality codes. Please see responses re IRO-001-4 for additional retirement justification.

TOP-001-4 R13

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TOP-001-4 R21

R20 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-001-4 R24

R23 already provides for two active paths and could address the concept of using the alternate periodically. A NERC certification program can ensure that the paths are being used periodically.

TOP-002-4 R3

The TOP's performance of the analysis is required by R1. A separately enforceable requirement that the TOP take the common-sense action of informing impacted entities is unnecessary. Could be verified through NERC certification.

TOP-002-4 R4, R5, and R7

Daily Operating Plans are not needed for BAs. Generation dispatch information can be gathered and shared through data provision requirements.

TPL-007-1 R1

Administrative.

VAR-001-4.1 R1

Duplicative of FAC-014.

VAR-001-4.2 R5

All of R5 appears to be administrative and a common-sense operations item. All entities keep impedance and tap information on their transformers. There isn't any reason to withhold information if requested, so a mandatory standard backed by sanctions to provide information within 30 days is simply an administrative clock. It's wasteful of both entity and regulator resources.

VAR-002-4.1 R3

Duplicative of other standards requiring data provision. There is no justification for the 30 minute timing requirement; if a timing requirement is retained, it is not a good reliability practice to require notification "within 30 minutes," but only if status is not restored within 30 minutes.

VAR-002-4.1 R4

Duplicative of other standards requiring data provision. There is no justification for a 30 minute time limit and this becomes a compliance trap.

VAR-002-4.1 R5

Duplicative of other standards requiring data provision.

Likes 0	
Dislikes 0	

Response

Patti Metro - National Rural Electric Cooperative Association - 3,4

Answer	Yes
Document Name	

Comment

Suggest the following be considered for retirement:

1, COM-001-3 – R7, R11, and R13 –Interpersonal communication capabilities is inherent in the ability of a registered entity to conduct real-time operations of the BES, therefore these requirements are administrative and create an undue documentation burden for the applicable entities.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

The NSRF makes the following recommendations for review for retirement. The NSRF is using similar rationale as we previously submitted in our SER Matrix on 2/1/2018, as our views on retirement have not changed. The NSRF also understands that Phase 2 may combine or modify Requirements but simply combining or modifying Requirements do not necessarily reduce an Entity's workload, cost, or compliance risks. It would be beneficial if an outline of Phase 2 was published so we would know if our below concerns are within Phase 2.

COM-001-3, entire Standard. Rational: This Standard requires a communication device (Interpersonal Communications) which is something that every business needs to be successful. While a communication device (phone) is certainly necessary in a control center, requiring a phone adds compliance burden to an objective that is already being achieved. This standard does not increase reliability by requiring a means to something, communication, which is required to stay in business and reliable. Additionally, what data exists to support this Standard? Have Entities failed to have a primary and alternate phone in the past? Have chronic phone failures plagued our industry? We believe that every Entity has multiple business (corporate phones, radios, satellite phones, texting communication systems, etc.) and not to mention personal communication devices which the Standard does not preclude. Recommend this Standard be added to this SAR for retirement.

PER-003-1, part 1.1, 2.1, 3.1, Areas or Competency. Rationale: This requirement is covered in the NERC Certification Program. All Applicable entities have no control over the "Areas of Competency" which are contained in the NERC Certification program. The PCGC assures that the areas of competency are within the NERC certification exam. Each Entity will use PER-005-2 to define their "Tasks" that need to be mastered and may not line up with the NERC prescribed Areas of Competency(s). These "minimum" Areas of Competency can only be achieved by passing the applicable NERC System Operator exam. Recommend their parts be added to this SAR for retirement.

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5

Answer	Yes
Document Name	

Comment

meant to click on No

Likes 0	
Dislikes 0	

Response
Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	
Document Name	

Comment
No Comment

Likes 0	
Dislikes 0	

Response
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment
No comment

Likes 0	
Dislikes 0	

Response