Comment Report

Project Name:	2021-01 Modifications to MOD-025 and PRC-019 | Draft 2
Comment Period Start Date:	4/25/2023
Comment Period End Date:	6/8/2023
Associated Ballots:	2021-01 Modifications to MOD-025 and PRC-019 MOD-025-3 AB 2 ST 2021-01 Modifications to MOD-025 and PRC-019 MOD-025-3 Implementation Plan AB 2 OT 2021-01 Modifications to MOD-025 and PRC-019 PRC-019-3 AB 2 ST 2021-01 Modifications to MOD-025 and PRC-019 PRC-019-3 Implementation Plan AB 2 OT

There were 70 sets of responses, including comments from approximately 178 different people from approximately 120 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree the language proposed in MOD-025-3 Requirement R1 and R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

2. Do you agree the language proposed in MOD-025-3 Requirement R3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. Do you agree the language proposed in MOD-025-3 Requirement R4? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. Do you agree the language proposed in MOD-025-3 Attachment 1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

5. Do you agree the language proposed in MOD-025-3 Attachment 2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

6. Do you agree the language proposed in MOD-025-3 Attachment 3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

7. The SDT believes the language of MOD-025-3 addresses the issues outlined in the two SARs in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

8. The SDT proposes a 1-year implementation plan for MOD-025-3 Requirements R3 and R4, with an additional 2 years (3 years total) for compliance with Requirements R1 and R2. For Requirements R1 and R2 with reoccurring periodicity for existing Facilities, the Implementation Plan proposes applicable entities shall initially comply within 66 calendar months of their last performance under the respective requirements of MOD-025-2 (Requirement R1, R2, and R3). Would these proposed timeframes give enough time to put into place process, procedures or technology to meet the proposed language? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

9. Do you agree the language proposed in PRC-019-3 Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

10. Do you agree the language proposed in PRC-019-3 Requirement R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

11. Do you agree the language proposed in PRC-019-3 Attachment 1? If you do not agree, please provide your recommendation and, if

appropriate, technical or procedural justification.

12. The SDT believes the language of PRC-019-3 addresses the issues outlined in the two SARs in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

13. The SDT proposes a 1-year implementation plan for PRC-019-3 Requirement R2, with an additional 1 years (2 years total) for compliance with Requirements R1. The reoccurring 5-year periodicity of Requirement R1 has been removed. Would these proposed timeframes give enough time to put into place process, procedures or technology to meet the proposed language? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
DTE Energy - Detroit Edison Company	Adrian Raducea	5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,SPP RE,WECC	SRC 2023	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC
					Matt Goldberg	ISONE	1	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Elizabeth Davis	PJM	2	RF
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
Santee Cooper	Chris Wagner	1		Santee Cooper	Debbie Schneider	Santee Cooper	1,3,5,6	SERC
					Paul Camilletti	Santee Cooper	1,3,5,6	SERC
					Anthony Noisette	Santee Cooper	1,3,5,6	SERC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy	5	RF

						Group, Inc.		
					David Boeshaar	WEC Energy Group, Inc.	6	RF
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire	1	MRO

						Hathaway Energy - MidAmerican Energy Co.		
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO
					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Michael	Michael		WECC	PG&E All	Marco Rios	Pacific Gas	1	WECC

Johnson	Johnson			Segments		and Electric Company		
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					Frank Lee	Pacific Gas and Electric Company	5	WECC
Southern Company - Southern Company Services, Inc.	Pamela Frazier	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont	1	NPCC

	Electric Power Company		
James Grant	NYISO	2	NPCC
John Pearson	ISO New England, Inc.	2	NPCC
Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
Randy MacDonald	New Brunswick Power Corporation	2	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Glen Smith	Entergy Services	4	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	5	NPCC
Tracy MacNicoll	Utility Services	5	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC

					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
					Joshua London	Eversource Energy	1	NPCC
Stephen Whaite	Stephen Whaite			ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD / BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC
Associated Electric Cooperative,	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative	1	SERC

Inc.						(Missouri)		
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Do you agree the language proposed in MOD-025-3 Requirement R1 and R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation disagrees with the change from 90 days to 30 days within which to provide information to the Transmission Planner. Reclamation recommends 90 days is the proper amount of time for entities to complete their required internal review and routing processes before providing information to an outside entity.	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	No
Document Name	
Comment	
Tacoma Power agrees with the language proposed for MOD-025-3 R2. However, Tacoma Power does not agree to the proposed changes for MOD-025-3 R1 and the references to Attachment 1. Instead of referring to Attachment 1, Tacoma Power recommends incorporating the required actions from Attachment 1 into the Requirement R1 language as sub-Requirements. The proposed MOD-025 Attachments include a mix of both actions needed for compliance and optional guidance for how to comply. This mix is confusing for entities who are trying to understand the baseline for compliance, and may also confuse ERO auditors who interpret the examples as required evidence. Tacoma Power recommends moving the examples or guidance of how to comply to either the Technical Rationale or an Implementation Guide.	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No

Document Name	
Comment	
WEC Energy Group supports the MRO NSRF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
The verification process should be simplified and adding more description to the process may not translate to more accuracy in the modeling. Some of the proposed required verifying documentation is irrelevant or/ and is covered in other NERC standards such as the manufacturer-supplied thermal capability curve (D-curve) for the old plant ((some of these facility has been updated/modified such as rating changes due to winding update, or excitation and governor/turbine change), the development of facility D-cure (instead of verification it), the limiters (that has been provided as part of PRC-019). As stated I think the level of detailed additional information that is needed should be left to the planners depending on the quality of the submitted data to address any modeling issues.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The changes to MOD-025 largely involve making mandatory the corrections of MOD-025-2 Note 2, but this is proposed to be done for GOs only. Such an approach will not work. None of the TPs we deal with accept MOD-025-2 Note 2 corrections, and there is no point to making GOs do more work just to have their results discarded. MOD-025-3 should require TPs to accept and use the corrected results.	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA supports comments submitted by the US Bureau of Reclamation that 90-days, not 30-days, is an appropriate timeframe for entities to provide information to an external entity after verification.	
Likes 0	
Dislikes 0	
Response	

Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
There appears to be a lot of discussion in the industry questioning the usefulness for MOD-025.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports comments from EEI related to Q1 and Q4 which state: EEI does not support the reduction of time from 90 days to 30 days for responsible entities to comply with Requirements R1 and R2. The proposed changes are administrative and do not conform to the principles previously identified in the Paragraph 81 initiative. (Ref. Paragraph 81 Criteria - B1. Administrative - The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. Administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.) While EEI recognizes that these Requirements provide TPs with verified Real and Reactive Power capability for applicable facilities, we are unaware of any Reliability improvements that would be achieved by reducing the reporting time from 90 days to 30 days. EEI further notes that work conducted under Requirements R1 and R2 often requires the assistance of third-party contractors/consultants necessitating the need for the continuance of the 90-day timeframe.	

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Remove extraneous “R1.3.2 and R2.3.2 Composite capability curve” requirements that produce Composite Figure 1: Example Composite Capability Curve for Synchronous Generator. PQ Data Table requirement provides adequate data and should be retained.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response

Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese

Answer	No
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State does not agree with the 30 day calendar verificaiton date for R1 and R2. Tri-State suggests a 90 day calendar verification date.	
Likes 0	
Dislikes 0	

Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The MRO NSRF is concerned that Requirement R1 & R2 is not meeting the intention of the SAR's scope. The MRO NSRF does not believe these requirements are fulfilling the following scope items: 1. Revisions to MOD-025-2 to ensure that verification activities produce data and information that can be used by Transmission Planners and Planning Coordinators for the purposes of developing accurate and reasonable plant active and reactive capability data (including possibly representation of the "composite capability curve" inclusive of capability and limiters, where applicable). 2. Ensure that each Planning Coordinator and the area Transmission Planners develop requirements for the Planning Coordinator area real and reactive capability data verification 3. Ensure that Generator Owners provide the data specified by the Planning Coordinator and Transmission Planners for the Planning Coordinator area The MRO NSRF believes to achieve SAR Scope Item 1, then SAR Scope Item 2 must be developed by the Transmission Planners and Planning Coordinators and include SAR Scope Item 3, et al. This approach would be similar to the approach of Transmission Planners & Planning Coordinators such ERCOT, PJM & IESO whom have specifications for Real & Reactive Power testing and reporting.	
Likes 0	

Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
Cowlitz County PUD No. 1 disagrees with shortening the timeline from 90 days to 30 days within which to provide information to the Transmission Planner and recommends keeping with the current 90 days timeline.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF does not support the reduction of time from 90 days to 30 days for responsible entities to comply with Requirements R1 and R2. The proposed changes are administrative and do not conform to the principles previously identified in the Paragraph 81 initiative. We are unaware of any Reliability improvements that would be achieved by reducing the reporting time from 90 days to 30 days. We note that work conducted under Requirements R1 and R2 often requires the assistance of third-party contractors/consultants necessitating the need for the continuance of the 90 day time frame.	

Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	

Response

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF

Answer	No
Document Name	

Comment

Southern Indiana Gas & Electric Company (SIGE) supports comments submitted by the EEI and would request having a reporting period longer than 30 days for R1 and R2.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS supports the following comments submitted by EEI on behalf of its members:

EEI does not support the reduction of time from 90 days to 30 days for responsible entities to comply with Requirements R1 and R2. The proposed changes are administrative and do not conform to the principles previously identified in the Paragraph 81 initiative. (Ref. Paragraph 81 Criteria - B1. Administrative - The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. Administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources. While EEI recognizes that these Requirements provide TPs with verified Real and Reactive Power capability for applicable facilities, we are unaware of any Reliability improvements that would be achieved by reducing the reporting time from 90 days to 30 days. EEI further notes that work conducted under Requirements R1 and R2 often requires the assistance of third party contractors/consultants necessitating the need for the continuance of the 90 day timeframe.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	No

Document Name	
Comment	
Enel supports comments made by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company does not support the reduction of time from 90 days to 30 days for responsible entities to comply with Requirements R1 and R2. The proposed changes are administrative and do not conform to the principles previously identified in the Paragraph 81 initiative. We are unaware of any Reliability improvements that would be achieved by reducing the reporting time from 90 days to 30 days. We note that work conducted under Requirements R1 and R2 often requires the assistance of third party contractors/consultants necessitating the need for the continuance of the 90 day time frame. Southern Company also does not support a composite capability curve or PQ data table. This is redundant representation of data and requires multiple iterations of an engineering analysis to complete. We recommend changing the language in the first sentence of Attachment 2 such that it does not state “a completed report shall contain the following information at a minimum per R1&R2” so that entities can choose the reporting options that are appropriate but not be subject to having to submit all of the parts listed as a requirement.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM supports with EEI comments.	
Likes 0	

Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Entergy does not support a Yes vote for Requirement R1.3 or M1. Use of a vendor, such as Kestrel, to perform test and provide a report will take more than the proposed 30 calendar days to generate the test report, complete Site reviews of the report, address/incorporate comments, generate the Engineering change to create the associated Engineering Report, and transmit the Engineering Report to Transmission Planner. Recommend keeping the 90-calendar day requirement from MOD-025-2.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
R1 and R2 require the GO and TO to send information to the TP even if that information is not needed by the TP. R1 and R2 could be updated to require the GO/TO to send this information when requested by a TP, PC, or other functional registration when required for modeling. Furthermore, R1 and R2 leave open the possibility that the tests that are run by the GO/TO may not be performed under the parameters required by the modeling party. This could result in unusable modeling data or the need to re-run the tests. If the data is needed for modeling, then MPC suggests drafting a requirement that allows the modeling party to specify that the test is run under specific conditions, if possible. Some language that makes the parameters “mutually agreeable” would protect the GO/TO from unreasonable requests but has the potential to lead to a situation where the two parties cannot come to terms. MPC acknowledges that many details would need to be considered in writing the requirement this way. MPC also supports MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	No

Document Name	
Comment	
Entergy has numerous concerns with requirements in proposed standard change reference to comments submitted with this ballot.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource supports the comments submitted by EEI and the NPCC RSC.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comemnts of the Edison Electric Institute (EEI) to questions #1.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	

NIPSCO does not support the reduction of time from 90 days to 30 days to comply with Requirements R1 and R2, and believes 90 days is the proper amount of time for review and routing.

Likes 0	
Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1

Answer	No
Document Name	

Comment

NPPD submits to the SDT that MOD-025 verification data is, in some cases, more appropriately submitted by the GO to the Planning Coordinator. In the SPP RTO region, the PC is responsible for building the regional planning models (powerflow, dynamics, and short circuit) in accordance with MOD-032, and has an established annual schedule for submission of modeling information. The PC builds the regional planning models and through this process SPP screens the information for model usability and acceptability per the SPP regional modeling requirements. This process is outlined on their website at SPP.org and documented in the MDAG modeling data submittal requirements.

SPP is the Transmission Provider and is the ultimate authority for the collection of detailed modeling data from the Generator Owner and Interconnection Customer.

NPPD recommends the addition of Planning Coordinator to Section 4. Applicability, and modification of Requirement R1.3. language as follows: “1.3. Submit the following information, in accordance with Attachment 2, to the Transmission Planner **or Planning Coordinator as appropriate, in accordance with Generator Interconnection Agreements,** within 30 calendar days after the verification date. The verification date, as specified in Attachment 2, should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity.”

Additionally, NPPD supports the comments submitted by MRO NSRF.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation does not agree with the shortened time period for submittal to Transmission Planner from 90 to 30 calendar days. External vendors are routinely hired to perform the testing for the Generator Owner and a 30 day window does not provide enough time to receive the report from the vendor and then perform the necessary internal reviews to ensure accuracy. In addition, many Transmission Planners still use their own version of a spreadsheet/form to gather the test data in lieu of the MOD-025 Attachment and typically allow for a longer submittal window that was is currently being proposed. Constellation requests that obligation on what form to provide modeling data, and the submission timeline be decided by each applicable Transmission Planner and not prescribed by the NERC Standard or be reverted back to the current 90-day submission window. The proposed language is now requesting "one per unit voltage" calculation without any supporting methodology. This is not feasible for typical testing conditions as most synchronous generating units will need to increase voltage to 1.05 per unit in lagging and 0.95 per unit leading during operational testing to be able to produce the necessary VARs. Constellation requests the SDT provide additional guidance on how the "one per unit voltage" is intended to be used. Constellation also requests that the SDT evaluate the implications of on-line test data not matching the engineering analysis. This mismatch could occur due to ambient temperature of air-cooled machines, system limitations, sister unit var output if online during the test, river flow for hydro generating units, generator terminal voltage limits, etc. This mismatch of data could potentially cause the Transmission Planner to reject the test results of a generating unit and therefore require the Generator Owner to re-perform the test

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer

Answer	No
Document Name	

Comment

Minnesota Power supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	No
Document Name	

Comment

Black Hills Corporation does not support the proposed language for Requirement R1 and R2. As a whole, the majority of entities utilize third party vendors/consultants and the full 90 days currently applicable is needed.

Likes 0	
Dislikes 0	

Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation does not support the proposed language for Requirement R1 and R2. As a whole, the majority of entities utilize third party vendors/consultants and the full 90 days currently applicable is needed.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation does not support the proposed language for Requirement R1 and R2. As a whole, the majority of entities utilize third party vendors/consultants and the full 90 days currently applicable is needed.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP disagrees with changing verification period from 90 days to 30. In general language should be adjusted to state that the GO needs to provide the test results to the TP of the interconnected Transmission System. The NERC ROP does not require a GO to map to a TP. This is the largest gap to the models getting accurate data.	
Likes 0	

Dislikes 0	
Response	
Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC supports comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support the reduction of time from 90 days to 30 days for responsible entities to comply with Requirements R1 and R2. The proposed changes are administrative and do not conform to the principles previously identified in the Paragraph 81 initiative. (Ref. Paragraph 81 Criteria - B1. Administrative - The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome. Administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.) While EEI recognizes that these Requirements provide TPs with verified Real and Reactive Power capability for applicable facilities, we are unaware of any Reliability improvements that would be achieved by reducing the reporting time from 90 days to 30 days. EEI further notes that work conducted under Requirements R1 and R2 often requires the assistance of third party contractors/consultants necessitating the need for the continuance of the 90 day timeframe.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	

Constellation does not agree with the shortened time period for submittal to Transmission Planner from 90 to 30 calendar days. External vendors are routinely hired to perform the testing for the Generator Owner and a 30 day window does not provide enough time to receive the report from the vendor and then perform the necessary internal reviews to ensure accuracy. In addition, many Transmission Planners still use their own version of a spreadsheet/form to gather the test data in lieu of the MOD-025 Attachment and typically allow for a longer submittal window that was is currently being proposed. Constellation requests that obligation on what form to provide modeling data, and the submission timeline be decided by each applicable Transmission Planner and not prescribed by the NERC Standard or be reverted back to the current 90-day submission window.

The proposed language is now requesting “one per unit voltage” calculation without any supporting methodology. This is not feasible for typical testing conditions as most synchronous generating units will need to increase voltage to 1.05 per unit in lagging and 0.95 per unit leading during operational testing to be able to produce the necessary VARs. Constellation requests the SDT provide additional guidance on how the “one per unit voltage” is intended to be used.

Constellation also requests that the SDT evaluate the implications of on-line test data not matching the engineering analysis. This mismatch could occur due to ambient temperature of air-cooled machines, system limitations, sister unit var output if online during the test, river flow for hydro generating units, generator terminal voltage limits, etc. This mismatch of data could potentially cause the Transmission Planner to reject the test results of a generating unit and therefore require the Generator Owner to re-perform the test.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

R1: We would like more clarification on what kind of engineering analysis is acceptable.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC

Answer	No
Document Name	

Comment

SMUD and BANC support the comments provided by Tacoma Power.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	No
Document Name	
Comment	
R1.3.2: Suggest writing the complete term followed by the acronym when referencing the acronym PQ for the first iteration. R2.3: Suggest specifying who (the TO?) is responsible to complete the engineering review or analysis?	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	

: PG&E supports the comments provided by the Edison Electric Institute (EEI) related to the reduction in time from 90 days to 30 days.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We recommend the language of R1 be revised as follows:

R1. For each of their applicable Facilities, each Generator Owner shall verify the Real and Reactive Power capability in accordance with Attachment 1 and inform its Transmission Planner as follows:

1.1. Provide a report to the Transmission Planner, containing the information specified in Attachment 2, within 90 calendar days after the verification date (see footnote 1).

(footnote 1) The "verification date" represents the date that the Generator Owner's engineering review or engineering analysis is complete and serves as the basis for the recurring 120 calendar month maximum interval for existing applicable Facilities.

The proposed Draft 2 language for R1 and parts 1.1 and 1.2 seems cumbersome. We suggest combining into R1 and rewording.

As noted in our comments on Draft 1, we believe the time allowed to submit the required information to the Transmission Planner should be "within 90 calendar days after the verification date" rather than 30 calendar days. For verifications that can occur up to ten years apart (for an existing applicable Facility), the reduction from 90 calendar days (in MOD-025-2) to 30 calendar days seems unwarranted.

We recommend moving language that explains the "verification date" to a footnote.

We recommend removal of the proposed Draft 2 language for R1 parts 1.3.1 – 1.3.3 since this is redundant with language in Attachment 2.

We recommend the language of R2 be revised as follows:

R2. For each of their applicable Facilities, each Transmission Owner shall verify the Real and Reactive Power capability in accordance with Attachment 1 and inform its Transmission Planner as follows:

2.1. Provide a report to the Transmission Planner, containing the information specified in Attachment 2, within 90 calendar days after the verification date(see footnote 2).

(Footnote 2) The "verification date" represents the date that the Transmission Owner's engineering review or engineering analysis is complete and serves as the basis for the recurring 120 calendar month maximum interval for existing applicable Facilities.

The rationale for these recommended changes is the same as for R1 noted above.

Likes 0	
Dislikes 0	

Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	

MOD-025-3 does not address the fundamental concern of inaccurate model data. The verification described does not appear to provide usable data to Transmission Planners for modeling purposes and it is unclear what the data should be used for.

Pmax, Pmin, Qmax, and Qmin results are not adequate to be used in the models for the following reasons:

o Test results must be corrected for various factors (weather, temperature, etc.) in order to compare or translate into the model. Transmission Planners may not be capable of performing or understanding corrections and the corrections are not going to be perfect. Validating Pmax, Pmin, Qmax, and Qmin given these corrections provides only a ballpark comparison with potentially significant accuracy issues.

o Test results are dependent on the current grid state, and are not adequate for comparison as written in MOD-025-3.

o Testing does not test the limits of the inverters or turbines themselves because it may stop at 0.95 PF or Power Plant Controller limits. If inverters or turbines are down, others may be able to compensate for their lack of output – however, this testing will not capture limits on inverters/turbines themselves that may have been incorrectly programmed. As this reads as more of a performance test standard, this is a performance issue that would not be tested.

Section 3 – “All aux equipment in service for normal operation.” Recommend the SDT to consider how this may impact testing. For example, capacitors switching in during testing will back the inverters/turbines off from providing support. If the intention of the requirement is to find the true limits of inverters or turbines, it may be advantageous to consider testing without aux equipment in normal operation.

Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

30 days is too agressive to provide final data to TP.

Likes 0	

Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
AEPC signed on to ACES comments below: While we have no specific issue with the language of the proposed Requirements R1 and R2, the language in both is nearly identical. We recommend combining Requirements R1 and R2 into a single requirement.	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	
R1.3.2: Suggest writing the complete term followed by the acronym when referencing the acronym PQ for the first iteration. R2.3: Suggest specifying who (the TO?) is responsible to complete the engineering review or analysis?	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI is supportive of the comments provided by the NAGF.	

Likes 0	
Dislikes 0	

Response

James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns

Answer	Yes
Document Name	

Comment

The only potential concern would be reliance on strictly engineering analysis for the verification. Some tie to test results (Pmax testing, De Mello zero-power factor load rejection) should be used.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	Yes
Document Name	

Comment

While we have no specific issue with the language of the proposed Requirements R1 and R2, the language in both is nearly identical. We recommend combining Requirements R1 and R2 into a single requirement.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

Likes 0	

Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC - no Comment From response received from Standard Owners or SMEs	
Likes 0	
Dislikes 0	
Response	
Bret Galbraith - Seminole Electric Cooperative, Inc. - 6	
Answer	
Document Name	
Comment	
PRC-019 The 90-day period allowed Generation Units the ability to make changes to protection control equipment and associated devices, validate the changes via testing and report. It also allowed the unit to return to service, undergo requirement testing, and produce a report. The 90-Day period also provided time to make any required adjustments and update the report. The Technical Rational implies that the 90-day period is only for minor changes and a formal evaluation must be performed prior to making any changes. The Technical Rational also implies that all units should already meet PRC-019 requirements either before or as they return to service which would result in either significant downtime or increased costs for operation.	

PRC-019

Expanding the requirement to include the distributed control system is unacceptable. The output of the distributed control system commands to the AVR are displayed in the coordination study for PRC-019 which proves coordination of the AVR limiters with the Protection Control Relay Trip limits. If the commands for voltage/VAR are held at a static point the response to the grid for voltage and VARs is controlled by the response time of the AVR not the distributed control system. The response of the Distributed Control System model is issued by the manufactured and verified in MOD-026. Reactive Power limitations are provided in MOD-025. In addition, the inclusion of Distributed Control System would create the need to identify specific control system points associated with the requirement and the scope would need to be limited to parameters associated with protection.

PRC-019

Seminole has concerns over the removal of the 5-year maximum time periodicity. Seminole requests additional rationale for this deletion.

MOD-025 R4

Second bullet allows a plan to be submitted but with no due date for completion of the plan. Why is this open ended?

MOD-025, Attachment 1, Section II

The value here of 20 MVA could be interpreted to mean that 20.4 MVA is rounded down to 20 MVA due to significant digits. Seminole requests NERC to clarify whether this should be 20 MVA or 20.0 MVA.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	

Comment

R1.3.2: Suggest writing the complete term followed by the acronym when referencing the acronym PQ for the first iteration.

R2.3: Suggest specifying who (the TO?) is responsible to complete the engineering review or analysis.

Likes 0	
Dislikes 0	

Response

2. Do you agree the language proposed in MOD-025-3 Requirement R3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
The proposed R3 language only requires TPs to perform a technical review of the provided documentation. They should be required to use the corrections-based documentation in their models.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E supports the input provided by the Edison Electric Institute (EEI) with agreeing on the proposed language, but the second bullet should be aligned with bullet #1 and provide clarification as to the criteria to be used as the basis for TP rejection of the GO or TOs information under Requirement R3.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
We also ask that some criteria be developed to clarify the intended criteria that would be used as a basis for TP rejection of the GO or TOs information under Requirement R3. Ameren would also like clarification on what kind of Planning Review is expected.	
Likes 0	

Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI is supportive of the comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI in part agrees with the proposed language in MOD-025-3, Requirement R3 but the second bullet (i.e., Notification that the GO or TO submittal contains a technical concern) should be aligned with the 1st bullet. To address this concern, we offer the following change to bullet 2 under Requirement R3; see bolded text:

- Notification that the Transmission Planner has reviewed the information and has identified a technical concern **with the Real and Reactive Power capability information submitted by the Generator Owner or Transmission Owner**, including the basis for the technical concern.

We additionally ask that some criteria be developed to clarify what would be used as a basis for TP rejection of the GO or TOs information under Requirement R3.

Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	

SRP supports Midwest Reliability Organization’s NERC Standards Review Forum’s (MRO NSRF) comments.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

Black Hills Corporation supports the NAGF comments.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	No
Document Name	

Comment

Black Hills Corporation supports the NAGF comments.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	No
Document Name	

Comment

Black Hills Corporation supports the NAGF comments.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer

Answer	No
Document Name	

Comment

Minnesota Power supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1

Answer	No
Document Name	

Comment

NPPD supports comments submitted by MRO NSRF.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comemnts of the Edison Electric Institute (EEI) to questions #2.

Likes 0	
Dislikes 0	

Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
A TP that receives information from a GO or TO may not have a use for the information. This requirement could be adjusted to specify the review only in situations where the information is needed for modeling purposes. The scope of R3 should also be expanded to include the PC, or other functional registrations that may have a need for and receive this information from a GO or TO. Also, a requirement to provide notification that no technical concerns have been identified does not support reliability. If an entity requires the information and indicates that they have a technical concern, then there is reasonable assurance that they have the information they need to perform their task.	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Entergy recommends that the language for the proposed MOD-025-3 R3 be revised to address the following:	

1. It is unclear what the measurement/evaluation criteria will be used by the Transmission Planner (TP) to review/verify the information submitted by the Generator Owner (GO).
2. How would we recognize the validity of capability curve and other limits like OEL? We would likely just accept the data and enter it in our models even though the tested data wouldn't reach the capability curve limits. The NERC standard needs to provide specifics on what the model quality test will look like as they do for MOD-026/027. Also, if the VAR capability decreased from what was previously reported, does FAC-002 come into play whereas this may be a material change that could impact the BES reliability that the TP would need to evaluate? The SAR drafting team should clarify whether the TP should assess such a change per FAC-002 when receiving a MOD-025 report if a TP analysis is required in MOD-025.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC

Answer	No
Document Name	

Comment

PNM supports with EEI comments.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company recommends that the language for the proposed MOD-025-3 R3 be revised to specify that the TP disclose what the measurement/evaluation criteria will be used to review/verify the information submitted by the Generator Owner (GO). This is the subject of the SAR Project Scope, Item 2.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC

Answer	No
Document Name	
Comment	

The requirement effectively brings the TP into the standard simply to provide an administrative function. It is agreed that any technical comments by the TP should be provided in writing if there are any comments at all. However, forcing the TP to provide a comment that there is or is not a technical issue is not necessary or appropriate for inclusion in a Reliability Standard. Additionally, the selection of a 90-day response period appears arbitrary.

If this requirement is retained, it should be reworded to state that any technical comments should be documented and provided in writing. The 90-day window should also be removed as it is possible the TP could come up with additional technical concerns beyond 90 days.

Likes 0	
Dislikes 0	
Response	

Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	
Comment	

Enel supports comments made by the MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	
Comment	

AZPS supports the following comments submitted by EEI on behalf of its members:

EEI in part agrees with the proposed language in MOD-025-3, Requirement R3 but the second bullet (i.e., Notification that the GO or TO submittal contains a technical concern) should be aligned with the 1st bullet. To address this concern, we offer the following change to bullet 2 under Requirement R3; see bolded text:

- Notification that the Transmission Planner has reviewed the information and has identified a technical concern **with the Real and Reactive Power capability information submitted by the Generator Owner or Transmission Owner**, including the basis for the technical concern.

We additionally ask that some criteria be developed to clarify the intended criteria that would be used as a basis for TP rejection of the GO or TOs information under Requirement R3.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF recommends that the language for the proposed MOD-025-3 R3 be revised to address the following:

a. It is unclear what the measurement/evaluation criteria will be used by the Transmission Planner (TP) to review/verify the information submitted by the Generator Owner (GO).

b. Modify the proposed R3 language to state that the TP must recognize the validity of and use the composite capability curve (CCC) and PQ data, not just review the information submitted by the GO.

Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	

Response

George E Brown - Pattern Operators LP - 5

Answer	No
Document Name	

Comment

Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.

Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No

Document Name	

Comment

While the MRO NSRF understands the importance of having an open feedback loop between the submitter and reviewer, the MRO NSRF is concerned that Requirement R3 is not meeting the intention of the SAR's scope. The MRO NSRF does not believe this requirement is fulfilling the following scope items:

2.Ensure that each Planning Coordinator and the area Transmission Planners develop requirements for the Planning Coordinator area real and reactive capability data verification

5. Ensure that data provided by the applicable Generator Owners and Transmission Owners is analyzed and used appropriately by Transmission Planners and Planning Coordinators

The MRO NSRF is also concerned with the '90 calendar day' requirement. The SAR's scope makes no mention of adding timeframes to the requirements. In addition, the MRO NSRF is uncertain if 90 calendar days is enough time for Transmission Planner to review & respond, or the methodology used to choose the timeframe. The MRO NSRF suggests instead, is allowing the Transmission Planner, as a part of the SAR Scope item 2, to specify timeframes that they will acknowledge and reply within.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Delete R3 and M3 because the MOD-025 verification process does not require additional information from the TP and the GO has sufficient information and technical expertise to determine the capability of the machine (including historical operational data). A 90-day feedback requirement from the TP is unnecessary and adds undue compliance burden. Also, in MOD-025-2 R3, the scope of the “review the information” is vague and doesn’t provide sufficient instruction for the TP to follow.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No

Document Name	
Comment	
Talen supports the comments of the NAGF. Additionally, TPs should be required to accept corrected values as the true reactive capability of generators, amd make use of this data in their models.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the MRO NSRF and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation does not have any comments on R3 as it is not applicable to Generation Owners. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes

Document Name	
Comment	
We support RSC comments	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation does not have any comments on R3 as it is not applicable to Generation Owners Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz County PUD No. 1, 5, 6/7/2023	
Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	Yes

Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	

Manitoba Hydro agree that the new R3 requirement provides the needed feedback mechanism to address Transmission Planner concerns regarding any technical issues that it identifies with the Real or Reactive Power capability information. It should be left up to the Transmission Planner to communicate to the generation and transmission owners the required information required to address their concerns. The most efficient way to address the model accuracy issues is to encourage dialogue between entities to ensure that verifications are accurate and appropriate for the needs of the Transmission Planner.

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3,	

6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 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	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC - no Comment From response received from Standard Owners or SMEs	
Likes 0	
Dislikes 0	
Response	

3. Do you agree the language proposed in MOD-025-3 Requirement R4? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
See the NAGF comments for Question 3.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Revise R4 by removing the phrase “under Requirement 3” (required due to the deletion of R3).	
Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The MRO NSRF is also concerned with the '90 calendar day' requirement. The SAR's scope makes no mention of adding timeframes to the requirements. In addition, the MRO NSRF is uncertain if 90 calendar days is enough time for a Generator Owner to review & respond, or the methodology used to choose the timeframe. The MRO NSRF suggests instead, is allowing the Transmission Planner, as a part of the SAR Scope item 2, to specify timeframes to reply within. SAR scope item 2 is as follows: 2. Ensure that each Planning Coordinator and the area Transmission Planners develop requirements for the Planning Coordinator area real and reactive capability data verification	
Likes 0	
Dislikes 0	
Response	

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
See the NAGF comments for Question 2. In addition, the NAGF is concerned with the "90 calendar day" requirement. The SAR's scope makes no mention of adding timeframes to the requirements. Also, 90 calendar days may not be enough time for a Generator Owner to review & respond. Therefore, we suggest to allow the Transmission Planner, as a part of the SAR Scope item 2, to specify reply timeframes.	

Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	

Comment

Enel supports comments made by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC

Answer	No
Document Name	

Comment

Reference the comment to question #2.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company is concerned with the "90 calendar day" requirement. The SAR's scope makes no mention of adding timeframes to the requirements. Also, we are uncertain if 90 calendar days is enough time for a Generator Owner to review & respond. We suggest, instead, to allow the Transmission Planner, as a part of the SAR Scope item 2, to specify timeframes to reply within. SAR scope item 2 is as follows:

Ensure that each Planning Coordinator and the area Transmission Planners develop requirements for the Planning Coordinator area real and reactive

capability data verification.	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

Comment: Entergy recommends that the language for the proposed MOD-025-3 R4 be revised to address the following

1. It is unclear what the measurement/evaluation criteria will be used by the Transmission Planner (TP) to review/verify the information submitted by the Generator Owner (GO).
2. How would we recognize the validity of capability curve and other limits like OEL? We would likely just accept the data and enter it in our models even though the tested data wouldn't reach the capability curve limits. The NERC standard needs to provide specifics on what the model quality test will look like as they do for MOD-026/027. Also, if the VAR capability decreased from what was previously reported, does FAC-002 come into play whereas this may be a material change that could impact the BES reliability that the TP would need to evaluate? The SAR drafting team should clarify whether the TP should assess such a change per FAC-002 when receiving a MOD-025 report if a TP analysis is required in MOD-025.

Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	

MPC supports MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No

Document Name	
Comment	
NPPD supports comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	

Black Hills Corporation supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
The notification should not have a “plan” but a Corrective Action Plan” with a requirement to provide an updated CAP in the event that the milestones change.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	

AECI is supportive of the comments provided by the NAGF.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren would like clarification on a dispute resolution process for the third bullet point to avoid a potential impasse.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz County PUD No. 1, 5, 6/7/2023	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	

Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports the language proposed in MOD-025-3, Requirement R4.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation agrees with a 90-day requirement to receive feedback regarding models from the Transmission Planner; however, we are concerned that the additional data that this draft Standard is proposing may not even be used by the Transmission Planner. If this Standard is requiring the GO provide the additional data such as a one-line diagram, composite capability curve and associated PQ data table, documentation showing the engineering basis, verification methodology and/or applicable data for the verification method then Constellation suggests that the proposed Standard language be modified to allow an exception from certain parameters based on the Transmission Planner's individual needs for modeling. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	

We support RSC comments	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the language proposed in MOD-025-3, Requirement R4.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation agrees with a 90-day requirement to receive feedback regarding models from the Transmission Planner; however, we are concerned that the additional data that this draft Standard is proposing may not even be used by the Transmission Planner. If this Standard is requiring the GO provide the additional data such as a one-line diagram, composite capability curve and associated PQ data table, documentation showing the engineering basis, verification methodology and/or applicable data for the verification method then Constellation suggests that the proposed Standard language be modified to allow an exception from certain parameters based on the Transmission Planner's individual needs for modeling. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes

Document Name	
Comment	
PG&E supports the proposed Requirement R4 language.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
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	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC - no Comment From response received from Standard Owners or SMEs	
Likes 0	
Dislikes 0	
Response	

4. Do you agree the language proposed in MOD-025-3 Attachment 1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

ERCOT joins the comments submitted by the ISO/RTO Council Standards Review Committee (IRC SRC) (submitted under the group name SRC 2023) and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023

Answer	No
Document Name	

Comment

An overarching goal of this Project is to ensure that the Real and Reactive Power Capability data provided through verification activities produces suitable data for the purposes of developing accurate planning models used in reliability studies, the IRC SRC's highest priority concern with MOD-025 is that Transmission Planners get credible and reliable real and reactive power capability data for modeling purposes. This is underscored in the Technical Rationale for MOD-025 (page 5), Section II, Item 5: *The development of an accurate composite capability curve and associated PQ data table of Requirement R1 or Requirement R2 is paramount, so the data and information made available to Transmission Planners is more accurate*.

To illustrate the importance of this requirement, in July of 1999, PJM experienced heavy loads due to hot and humid conditions. Sufficient MWs were available (real time and reserves) to supply the load but transmission voltages were decaying due to insufficient reactive supply (this wide-spread voltage decline was a gradual decay throughout the day as demand increased). At that time, PJM's Energy Management System (EMS) had only nameplate D-Curve data which indicated adequate supply and reserves available to correct the voltage issues but in reality, many units had internal or external limitations that prevented the unit from providing that level of reactive support. As a result, PJM developed a method of determining and modeling more realistic values for each unit's reactive capability through testing. Link to additional information: https://www.nerc.com/pa/rrm/ea/System%20Disturbance%20Reports%20DL/1999SystemDisturbance.pdf

Attachment 1, Section II, Item 5 allows the applicable entity to use one or more methodologies to verify the Facility Real and Reactive Power capability for all equipment expected to be in-service for normal operation. One of the allowed methodologies for this verification is an engineering review. We believe that an engineering review alone is not sufficient for capability determination and verification. Some operational data must be utilized. As described in the SAR, Project Scope, item 4 (page 3), expansion of the engineering review was intended to ***complement*** and ***not replace*** the need for the operational data gained via verification activities.

Therefore, SRC asks the SDT to modify item 5 (bullet #3) to require an applicable entity perform a stage test or collect operational data along with engineering analysis for it to qualify as an acceptable methodology (see Technical Rationale for MOD-025, Attachment 1, Section III – Stage test and operational data specifications).

The SDT proposes to extend the 5-year periodicity to 10 years to be consistent with MOD-026 and MOD-027. However, the performance can be impacted by changes and degradation not captured by current standards. We believe that the 5-year periodicity should be retained.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AESCE does not agree with the deadline of 180 days to perform a verification test after a change of greater than 10% capacity. Section 3 – “All aux equipment in service for normal operation.” Recommend the SDT to consider how this may impact testing. For example, capacitors switching in during testing will back the inverters/turbines off from providing support. If the intention of the requirement is to find the true limits of inverters or turbines, it may be advantageous to consider testing without aux equipment in normal operation.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Proposed Attachments 1, 2 and 3 include excessive data collection and engineering efforts that will most likely require contracted testing engineering and do not provide useful information to the Transmission Planner comparable to the effort and cost that will be required to perform the work.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	

Comment

The changes to this standard are quite extensive and we appreciate the large amount of time and effort that the SDT put into making meaningful updates. However, we do not believe that 180 calendar days is a sufficient amount of time to complete the staged testing and engineering analysis for new applicable Facilities identified in Attachment 1, Section I, Item 2. As new facilities will be unlikely to have sufficient operational data for the purposes of MOD-025 verification, we recommend that this section be reverted to the previous value of 12 calendar months.

Furthermore, in Attachment 1, Section I, Item 4, the outage duration must be >= 180 calendar days AND overlap the scheduled verification date in order to be allowed to perform the verification within 180 calendar days of the Return to Service (RTS) date. Consider the following scenario showing why a defined outage timeframe could be an issue (Note: all dates and timeframes are completely arbitrary and for illustrative purposes only):

- Entity XYZ is the registered GO for Unit X.
- Unit X is a 100 MW Combustion Turbine (CT) that was last verified 9 years, 7 months ago per MOD-025-3.
- Unit X is scheduled to begin a 90-day hot gas path outage in 2 weeks (i.e. 9 years, 7 months, 14 days since last verification date).
- Due to the extensive nature of these types of outages and the massive quantity of wornout components being replaced with new like-in-kind components, the unit capability will increase following the outage; however, the increase will likely be < 10%.
    - Therefore, in order to provide the TP with the most accurate data, the GO plans to perform the MOD-025 verification with the new components installed immediately post RTS (i.e. within the 10-year verification period).
    - Based on the currently scheduled dates, this plan leaves plenty of margin to complete the MOD-025 verification in a timely manner.
- During the outage, a major issue is discovered requiring extensive rotor work on the CT.
    - These rotor repairs extend the length of the outage by an additional 51 days for a total outage time of 141 calendar days.
- As the extended outage time is < 180 days, Entity XYZ is now in violation of MOD-025-3 due to not performing the verification within the 10-year period.
    - Example schedule:
        - Last date of verification: 08/31/2013
        - MOD-025-3 Verification Deadline per R1: 08/31/2023
        - Outage Start Date: 04/14/2023
        - Projected Outage End Date: 07/13/2023
        - Actual Outage End Date: 09/02/2023

In the Scenario above, the GO is left with 3 possible choices. Either A) perform the verification prior to the scheduled outage or B) risk a violation if the outage gets extended or C) to extend the outage >= 180 days. In our opinion, none of the above choices are optimal. Please consider the following modified verbiage for Item 4.

"Verify an existing applicable Facility within 180 calendar days of its return to service date, if the Facility has a planned or unplanned outage which overlaps its scheduled verification date and has not had its capability verified within the past ten years."

Lastly, the language in Section 6 does not seem to align with the language in the other sections of Attachment 1. Section 6 references "steady-state composite capability curve (CCC)" in contrast to the "Facility's composite capability curve" referenced in Section 5. By using seemingly contrasting language, Section 6 seems to indicate that a capability curve is required for each individual unit as opposed to the Facility as a whole. We recommend modifying as follows:

"For an applicable Facility as identified in Section 4.2.1, 4.2.2, or 4.2.4.1, when performing verification on an individual unit basis, create a graphical representation of the Facility steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The Facility steady-state CCC shall include at a minimum the following…"

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E supports the input provided by the Edison Electric Institute (EEI), their reasoning and suggested modifications.	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Section II.7.2 and III.4 require the representation of “all” auxiliary equipment. There should be realistic limits to the size of an auxiliary sources that are required for reporting. If a separate auxiliary source connection (Point E, Station Service Transformer) provide load less than 0.5% of Pmax, reporting of auxiliary load should be excluded. In addition, the engineering analysis option requirement needs to have better tighter criteria /guidance around it so that it would be consistent subject to acceptance criteria. Finally, criteria for the TO should also be included for operational /staged testing and these parties held accountable for the test preparation and test conditions that will allow generators to be able to better meet their true capability limits.	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee’s comments. OPG has the following additional comments:	

Attachment 1, Section I. Periodicity of verification, #3

The Facility has been on a planned or unplanned outage **of 180 days or greater,** which overlaps its scheduled verification date. Verify the applicable Facility within 180 calendar days of its return to service date.

Suggest removing **"of 180 days or greater."**

Suggest changing “Facility Capability” to “Unit Capability.”

Attachment 1, Section II. Verification specifications for applicable Facilities, #5

“Utilize staged testing data, in accordance with Section III, obtained from a date within 365 calendar days prior to **verification** date, and perform engineering analysis as needed per Note 1, that validates the generatorFacility capability; or”

Suggest changing the word **verification** to **re-verification.**

Please provide additional clarification: If the verification date is proactively set for 8 year instead of 10 does that means that the test staged data should be no older than the seventh(7) year, OR would the test data taken on the seventh year be invalid because it is >365 calendar days from the 10 year periodicity requirement?

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1

Answer	No
Document Name	

Comment

Section 1, point 1: “responsible entity” seems to be more commonly used in the Reliability Standards than “applicable entity”. Furthermore, ssuggest specifying who (the TO?) is responsible to complete the engineering review or analysis?

2. In our opinion, there is no added value to specify a minimal Facility outage time of 180 days to be allowed to delay from verification. If the entity is unable to verify a Facility because of a planned or unplanned outage, no matter the length of the outage, the entity should be allowed to perform verification within 180 days following its return to service date.

Indeed, a minimal outage time of 180 days will actually force the entity to plan its verification on a 9.5-year period, instead of a 10-year period, in order to avoid a situation where an outage of less than 180 days would prevent them from meeting the planned verification date.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3,

6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC

Answer	No
Document Name	
Comment	

SMUD and BANC support the comments provided by Tacoma Power.

Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	
Comment	

We would like more clarification on what kind of engineering analysis is acceptable.

Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	
Comment	

AECI is supportive of the comments provided by the NAGF.

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5

Answer	No

Document Name	
Comment	

Constellation agrees with NAGF's comments and in addition provides the following comments in regards to Attachment #1:

Section 1, Item 2: Constellation does not agree with the verification of each new applicable Facility within 180 calendar days of its commercial operation date. There may be reasons for a company to declare "commercial operation date" prior to actual day-one operational date due to regional and state differences (e.g., project financing, commissioning testing). Constellation therefore recommends revising the language to state "within 180 days of initial synchronization to the grid"

Section 1, Item 3: Constellation agrees with the 10-year periodicity; however, Transmission Planners typically have more conservative testing requirements. As previously mentioned, the data and periodicity for testing is dictated by the Transmission Planners and therefore providing such specific requirements in MOD-025 will continue to result in discrepancies in data reported to meet the Transmission Planner requests and evidence documented to meet the Standard requirements.

Section 1, Item 4: Constellation does not agree with the 180-day timeline for a change in capacity due to economic concerns. Wind and hydro generating units will now be required to perform max leading and lagging testing. It is unclear if first test has to be staged as the form now requires a composite curve, PQ table and documentation showing methodology.

Section 3, Item 5: Constellation recommends rewording this as IBR facilities operate only in VAR or PF control modes.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	
Comment	

EEI does not support the following changes to Attachment 1:

Section I, Parts 2, 3, 4: EEI does not support the reduction of time for verification testing of applicable facilities from 12 calendar months to 180 days noting the periodicity for this testing has been increased from 5 years to 10 raising the question what Reliability improvement might be achieved by this reduction. The work associated with the proposed changes are significant and obligating entities to shorten their verification testing and engineering analysis appears to be unjustified. It is also important to recognize that many entities do not have the internal expertise to conduct these tests and need the assistance of consultant/contractor to conduct these verification tests and associated analysis. For these reasons, we do not support the proposed reductions.

Section II, Part 3.1. EEI requests additional clarity regarding the "simplified one-line diagrams" representing the facility. While we agree that the one-line should include GSU, generator, and auxiliary equipment information, as needed by the Transmission Planner, we do not agree that all station service loads at all voltage levels need to be shown on the one-line. If this is not intended, modification should be made to the language in Part 3.1 to make it clear this level of detail is not required.

Section II, Parts 6-8: Recommend removing requirement to create a composite capability curve (CCC). Transmission Planners have sufficient modeling information with Q Max & Q Min @ Pmin + Q Max & Q Min @ Pmax. A CCC will be tedious, and time consuming for GOs/TOs to create and provide little reliability benefit to a TP. The TP cannot input the CCC into their modeling software directly, and the data it provides is redundant with the data required by Att 2 Section III.

Section 3. Note 1: EEI requests that a technical basis be provided for Note 1 (Section 3/Attachment 1). This note points out that the revisions to MOD-025-3 may not provide usable results for TPs under certain conditions and in those cases a simulation or engineering analysis will be required to address the limitations of the verification testing. The changes to MOD-025 were initiated to solve this issue but this note seems to indicate that the same issues that resulted in failed verification tests in the past may continue in the proposed MOD-025-3, Draft 2 version. Additional clarity within the technical rationale justifying Note 1 is requested.

Likes 0	
Dislikes 0	

Response

Mohamed Derbas - Sempra - San Diego Gas and Electric - 1

Answer	No
Document Name	

Comment

In Section 2 of Attacheent 1, SDG&E votes Negative for the following reasons:

1- the verification was originally completed every 5 year and based on the new proposal it needs to be completed every 10 year which is not desirable.

2- It’s not acceptable to only verify the power capability of BES facilities using “Engineering Analysis”. The characteristic can be verified with measured data and engineering analysis together.

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	No
Document Name	

Comment

We do not agree with the direction of using engineering analysis to prove full capability. Rather we see cooperation between the TO and GO and having a requirement for the TO to support GO tests as better options rather than declare capability per tests and operational data.

Likes 0	

Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	
Comment	

1. Section 1, point 1: "responsible entity" seems to be more commonly used in the Reliability Standards than "applicable entity". Furthermore, ssuggest specifying who (the TO?) is responsible to complete the engineering review or analysis?

2. In our opinion, there is no added value to specify a minimal Facility outage time of 180 days to be allowed to delay from verification. If the entity is unable to verify a Facility because of a planned or unplanned outage, no matter the length of the outage, the entity should be allowed to perform verification within 180 days following its return to service date.

Indeed, a minimal outage time of 180 days will actually force the entity to plan its verification on a 9.5-year period, instead of a 10-year period, in order to avoid a situation where an outage of less than 180 days would prevent them from meeting the planned verification date.

Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	

SRP supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.

Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	

Black Hills Corporation supports the NAGF comments.

Likes 0	
Dislikes 0	

Response
Sheila Suurmeier - Black Hills Corporation - 5

Answer	No
Document Name	

Comment
Black Hills Corporation supports the NAGF comments.

Likes 0	
Dislikes 0	

Response
Claudine Bates - Black Hills Corporation - 6

Answer	No
Document Name	

Comment
Black Hills Corporation supports the NAGF comments.

Likes 0	
Dislikes 0	

Response
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer

Answer	No
Document Name	

Comment
Minnesota Power supports EEI’s comments.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation agrees with NAGF's comments and in addition provides the following comments in regards to Attachment #1: Section 1, Item 2: Constellation does not agree with the verification of each new applicable Facility within 180 calendar days of its commercial operation date. There may be reasons for a company to declare “commercial operation date” prior to actual day-one operational date due to regional and state differences (e.g., project financing, commissioning testing). Constellation therefore recommends revising the language to state “within 180 days of initial synchronization to the grid” Section 1, Item 3: Constellation agrees with the 10-year periodicity; however, Transmission Planners typically have more conservative testing requirements. As previously mentioned, the data and periodicity for testing is dictated by the Transmission Planners and therefore providing such specific requirements in MOD-025 will continue to result in discrepancies in data reported to meet the Transmission Planner requests and evidence documented to meet the Standard requirements. Section 1, Item 4: Constellation does not agree with the 180-day timeline for a change in capacity due to economic concerns. Wind and hydro generating units will now be required to perform max leading and lagging testing. It is unclear if first test has to be staged as the form now requires a composite curve, PQ table and documentation showing methodology. Section 3, Item 5: Constellation recommends rewording this as IBR facilities operate only in VAR or PF control modes.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1

Answer	No
Document Name	

Comment

NPPD supports comments submitted by MRO NSRF.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	
Comment	
NIPSCO does not support the reduction of time for verification of applicable facilities from 12 calendar months to 180 days. If assistance of consultants/contractors is needed to conduct these verification tests, 12 months is the correct time period.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comemnts of the Edison Electric Institute (EEI) to questions #4.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource supports the comments submitted by EEI and the NPCC RSC.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No

Document Name	

Comment

AEPC signed on to ACES comments below:

The changes to this standard are quite extensive and we appreciate the large amount of time and effort that the SDT put into making meaningful updates. However, we do not believe that 180 calendar days is a sufficient amount of time to complete the staged testing and engineering analysis for new applicable Facilities identified in Attachment 1, Section I, Item 2. As new facilities will be unlikely to have sufficient operational data for the purposes of MOD-025 verification, we recommend that this section be reverted to the previous value of 12 calendar months.

Furthermore, in Attachment 1, Section I, Item 4, the outage duration must be >= 180 calendar days AND overlap the scheduled verification date in order to be allowed to perform the verification within 180 calendar days of the Return to Service (RTS) date. Consider the following scenario showing why a defined outage timeframe could be an issue (Note: all dates and timeframes are completely arbitrary and for illustrative purposes only):

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• Unit X is scheduled to begin a 90-day hot gas path outage in 2 weeks (i.e. 9 years, 7 months, 14 days since last verification date).

• Due to the extensive nature of these types of outages and the massive quantity of wornout components being replaced with new like-in-kind components, the unit capability will increase following the outage; however, the increase will likely be < 10%.

o Therefore, in order to provide the TP with the most accurate data, the GO plans to perform the MOD-025 verification with the new components installed immediately post RTS (i.e. within the 10-year verification period).

o Based on the currently scheduled dates, this plan leaves plenty of margin to complete the MOD-025 verification in a timely manner.

• During the outage, a major issue is discovered requiring extensive rotor work on the CT.

o These rotor repairs extend the length of the outage by an additional 51 days for a total outage time of 141 calendar days.

• As the extended outage time is < 180 days, Entity XYZ is now in violation of MOD-025-3 due to not performing the verification within the 10-year period.

o Example schedule:

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 MOD-025-3 Verification Deadline per R1: 08/31/2023

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 Actual Outage End Date: 09/02/2023

In the Scenario above, the GO is left with 3 possible choices. Either A) perform the verification prior to the scheduled outage or B) risk a violation if the outage gets extended or C) to extend the outage >= 180 days. In our opinion, none of the above choices are optimal. Please consider the following modified verbiage for Item 4.

“Verify an existing applicable Facility within 180 calendar days of its return to service date, if the Facility has a planned or unplanned outage which overlaps its scheduled verification date and has not had its capability verified within the past ten years.”

Lastly, the language in Section 6 does not seem to align with the language in the other sections of Attachment 1. Section 6 references “steady-state composite capability curve (CCC)” in contrast to the “Facility’s composite capability curve” referenced in Section 5. By using seemingly contrasting language, Section 6 seems to indicate that a capability curve is required for each individual unit as opposed to the Facility as a whole. We recommend modifying as follows:

“For an applicable Facility as identified in Section 4.2.1, 4.2.2, or 4.2.4.1, when performing verification on an individual unit basis, create a graphical representation of the Facility steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The Facility steady-state CCC shall include at a minimum the following…”

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

MPC has several comments relating to Attachment 1:

- Attachment 1, Section II, Paragraph 6 and Attachment 2, Figure 1 and PQ Curve Data Table: Limiters are already documented as a part of PRC-019. This will not be impactful to MPC, but it is redundant.
- Attachment 1, Section II, Paragraph 6.5: I think there needs to be clarification– what is the “final PQ curve, which defines the normal operating range”? Is it where an entity normally operates or is it where an entity can operate based on limiters and other protective settings?
- Attachment 1, Section III, Paragraph 3: “Staged testing or operating conditions should be maintained constant for a sufficient time to ensure that the applicable Facility can perform…” That leaves a significant detail up to interpretation. Previously, we were required to maintain a specific time under the various test conditions (only having to touch and go on three of the four conditions while the fourth condition had to be maintained for at least 60 minutes). Additional guidance may be provided in Attachment 1, Section III, Paragraph 6, but it is unclear if the intent is to approach a limit and immediately move away from it.
- Attachment 2, Note 1:
    - Does the SDT plan to provide guidance for the simulation or engineering analysis that now is required when the transmission system conditions are such that the operational test does not meet the manufacturer’s D-curve? I realize the previous version of MOD-025 recommended a similar analysis, but it was not required. It does not appear to be optional now, making it not only mandatory, but also enforceable. This could represent a minor or major change with some financial impact to the way MPC currently conducts testing.
    - Regarding when to perform the analysis, at what point are we to consider the test data not matching the D-curve?

MPC also supports MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

The most important reliability objective for this standard is to ensure that the Real and Reactive Power Capability data provided through verification activities produces suitable data for the purposes of developing accurate planning models used in reliability studies. Transmission Planners need credible and reliable real and reactive power capability data for modeling purposes

Attachment 1, Section II, Item 5 allows the applicable entity to use one or more methodologies to verify the Facility Real and Reactive Power capability for all equipment expected to be in-service for normal operation. One of the allowed methodologies for this verification is an engineering review. An engineering review alone is not sufficient for capability determination and verification. Some operational data must be utilized. As described in the SAR, Project Scope, item 4 (page 3), expansion of the engineering review was intended to complement and not replace the need for the operational data gained via verification activities.

Facility performance can be impacted by changes and degradation not captured by current standards, as such, we believe that the 5-year periodicity should be retained.

Likes 0	
Dislikes 0	

Response

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Entergy recommends that the language for the proposed MOD-025-3 Attachment 1 be revised to address the following:

1. Retesting based upon nameplate values could result in more testing, more frequently on units whose prime mover is not capable of meeting name plate values. Small derates on these units which are insignificant as a whole could be larger than a 10% change from the name plate. Entergy Recommends Keeping the wording as current MOD-025-2 standard compared to previous verification It is unclear what engineering analysis is deemed acceptable.
2. T. Planning needs a CCC. We may run studies at different MW output levels than what the GO determines to be Pmax and Pmin and we also need other limits plotted on the curve like OEL.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC

Answer	No
Document Name	

Comment	
PNM supports with EEI comments.	
Likes 0	
Dislikes 0	
Response	

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	

- Att 1 Section I. 4. Propose a reword of "Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating" as this may lead to confusion. "Nameplate" changes are rare and reflect some sort of machine upgrade, stator rewind, etc. Possible alternative is "by more than 10 percent increase or decrease of previously reported real or reactive power capability."
- Att 1 Section II.3.1. Propose facility one-line not be so prescriptive in auxiliary equipment that has to be represented. The one-line should include GSU, generator, and auxiliary equipment information as needed by the Transmission Planner. As worded, the standard would imply all station service loads at all voltage levels need to be shown on the one-line.
- Att 1 Section II.6-8. Strongly recommend removing requirement to create a composite capability curve (CCC). Transmission Planner has sufficient modeling information with Q Max & Q Min @ Pmin + Q Max & Q Min @ Pmax. A CCC will be tedious and time consuming for GOs/TOs to create and provide little benefit to a TP. The TP cannot input the CCC into their modeling software directly, and the data it provides is redundant with the data required by Att 2 Section III.
- Att 1 Section III. What is the benefit of staged testing if it must be coupled with engineering analysis anyway?
- The PC/TP needs to have a say in the verification requirements as indicated by the SAR Project Scope.

Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Regarding Attachment One, Section III, Item 9, wording clarification is needed: "staged testing or operational data should be recorded with at least 90 percent of the inverters/generators ***normal operating real power*** at a Facility on-line"	
Likes 0	
Dislikes 0	

Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Enel supports comments made by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

AZPS supports the following comments submitted by EEI on behalf of its members:

Section I, Parts 2, 3, 4: EEI does not support the reduction of time for verification testing of applicable facilities from 12 calendar months to 180 days noting the periodicity for this testing has been raised from 5 years to 10 raising the question what Reliability improvement might be achieved by this reduction. The work associated with the proposed changes are significant and obligating entities to shorten their verification testing and engineering analysis appears to be unjustified. It is also important to recognize that many entities do not have the internal expertise to conduct these tests and need the assistance of consultant/contractor to conduct these verification tests and associated analysis. For these reasons, we do not support the proposed reductions.

Section II, Part 3.1. EEI requests additional clarity regarding the “simplified one-line diagrams” representing the facility. While we agree that the one-line should include GSU, generator, and auxiliary equipment information, as needed by the Transmission Planner, we do not agree that all station service loads at all voltage levels need to be shown on the one-line. If this is not intended, we ask that modification be made to the language in Part 3.1 to make it clear this level of detail is not required.

Section II, Parts 6-8: Recommend removing requirement to create a composite capability curve (CCC). Transmission Planners have sufficient modeling information with Q Max & Q Min @ Pmin + Q Max & Q Min @ Pmax. A CCC will be tedious, and time consuming for GOs/TOs to create and provide little benefit to a TP. The TP cannot input the CCC into their modeling software directly, and the data it provides is redundant with the data required by Att 2 Section III.

Section 3. Note 1: EEI requests that a technical basis be provided for Note 1 (Section 3/Attachment 1). This note points out that the revisions to MOD-025-3 may not provide useable results for Transmission Planners under certain conditions and in those cases a simulation or engineering analysis will be required to address the limitations of the verification testing. The changes to MOD-025 were initiated to solve this issue but this note seems to indicate that the same issues that resulted in failed verification tests in the past may continue in the proposed MOD-025-3, Draft 2 version. Additional clarity within the technical rationale justifying Note 1 is requested.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF recommends that the language for the proposed MOD-025-3 Attachment 1 be revised to address the following:

a. Section 1.4 - Propose a reword of “Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating” as this may lead to confusion. “Nameplate” changes are rare and reflect some sort of machine upgrade, stator rewind, etc. Possible alternative wording for consideration is “by more than a 10 percent increase or decrease of previously reported real or reactive power capability.”

b. Section II.3.1 – Recommend that the facility simple one-line diagram not be so prescriptive regarding auxiliary equipment that has to be represented. The one-line should include GSU, generator, and auxiliary equipment information as needed by the Transmission Planner. As worded, the standard would imply all station service loads at all voltage levels need to be shown on the one-line.

c. Section II.6 to II.8 - Recommend removing requirement to create a composite capability curve (CCC). Transmission Planner has sufficient modeling information with Q Max & Q Min @ Pmin + Q Max & Q Min @ Pmax. A CCC will be tedious and time consuming for GOs/TOs to create and provide little benefit to a TP. The TP cannot input the CCC into their modeling software directly, and the data it provides is redundant with the data required by Attachment 2 Section III.

d. Section III – The NAGF does not see the benefit of staged testing if it must be coupled with engineering analysis.

Likes 0	
Dislikes 0	

Response

Deanna Carlson - Cowlitz County PUD - 5

Answer	No
Document Name	

Comment

Cowlitz County PUD No. 1 supports the comments submitted by Tacoma Public Utilites.

Likes 0	
Dislikes 0	

Response

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The MRO NSRF believes the language in Attachment 1 is a vast improvement over the currently effective version of the standard. However, the MRO NSRF is not convinced that projects purpose as outlined in the SAR's scope is being met.

SAR Scope:

4. Revisions to MOD-025-2 to ensure that verification activities produce data and information that can be used by Transmission Planners and Planning Coordinators for the purposes of developing accurate and reasonable plant active and reactive capability data (including possibly representation of the "composite capability curve" inclusive of capability and limiters, where applicable).

5. Ensure that each Planning Coordinator and the area Transmission Planners develop requirements for the Planning Coordinator area real and reactive capability data verification

6.Ensure that Generator Owners provide the data specified by the Planning Coordinator and Transmission Planners for the Planning Coordinator area

The MRO NSRF believes to achieve SAR Scope Item 1, then SAR Scope Item 2 must be developed by the Transmission Planners and Planning Coordinators and include SAR Scope Item 3, et al. This approach would be similar to the approach of Transmission Planners & Planning Coordinators such ERCOT, PJM & IESO whom have specifications for Real & Reactive power testing and reporting.

Likes 0	
Dislikes 0	

Response

Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese

Answer	No
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Duke Energy recommends the SDT re-consider its following proposed language to ensure the intended outcome is achieved. The expected application of the criteria for a ‘change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating’ is unclear. Is the industry being asked to assess a change in capability to ensure they are staying within 10 percent of equipment nameplate rating or to assess the change against the last verified/reported capability to determine if it’s a 10 percent change of the nameplate rating? Recommend re-using the language from MOD-025-1, ‘changed by more than 10 percent of the last reported verified capability’ or make additional clarifications on comparing to nameplate rating so that the industry assesses the changes and derives nameplate

Real and Reactive Power ratings consistently and in accordance with the intent of the revised language. As an example, there could be scenarios such as a 400 MVA (320 MW, 240 MVAr) nameplate rated generator which has been previously MOD-025 verified/reported to reflect the unit/facility maximum Real Power capability of 280 MW [maximum output limited by a particular process/equipment rating, e.g. boiler limited]. There is a subsequent change that limits output to 250 MW (30 MW change). The 30 MW is less than 10 percent of nameplate, but more than 10 percent of last verified/reported. Is re-verification required?	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC Generator Working Group: #6-8: Requiring the composite curve is unnecessary as we are unsure the modeler can use that information. It is believed that they have sufficient MW/MVAR capability already	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	
WECC agrees with the intent but believes the language may be unclear so some. The language in Criteria 3 identifies a condition, but then also seems to require an action. The last sentence "Verify the applicable Facility within 180 calendar days of its return to service date" is not a condition, but rather, worded as a requirment. WECC believes the language from Criteria 5 in posting 1 was adequate. Criteria 6.1 and 8.1 of Section II don't seem to require anything definate. It requires equipment manufacture data, but then indicates if equipment manufacture data is not available, use the "best available data." Two concerns, 1) what does "not available" mean. How much effort should be put in to obtaining equipment manufacture data, and 2) what is "best available?" Could it be nothing more than a guess?	
Likes 0	
Dislikes 0	
Response	

Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	No
Document Name	
Comment	
RF recommends all MOD-025-3 Attachment 1 Section II Verification Specification 5 Methodology Options require the use of capability testing or operational data. RF recommends the "engineering review" option under the specification only be available for use to supplement capability testing results or operational data that has been obtained. Engineering review and/or analysis should be performed to adjust recorded values to account for limitations encountered during testing or operations that do not reflect the true capability of the units, but capability testing results or operational data should still be utilized to ensure unexpected limiting factors are identified. For additional context to support RF's recommendation, please reference Project Scope 4 and 6 from the publicly posted SAR as well as the Recommendation section of the publicly posted Power Plant Model Verification Task Force White Paper on MOD-025 Testing.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI's Comment which state: EEI does not support the following changes to Attachment 1: Section I, Parts 2, 3, 4: EEI does not support the reduction of time for verification testing of applicable facilities from 12 calendar months to 180 days noting the periodicity for this testing has been raised from 5 years to 10 raising the question what Reliability improvement might be achieved by this reduction. The work associated with the proposed changes are significant and obligating entities to shorten their verification testing and engineering analysis appears to be unjustified. It is also important to recognize that many entities do not have the internal expertise to conduct these tests and need the assistance of consultant/contractor to conduct these verification tests and associated analysis. For these reasons, we do not support the proposed reductions. Section I, Part 4: EEI questions whether the proposed wording of part 4 might be better stated as follows: Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects **the previously reported real or reactive** capability by more than a 10 percent increase or decrease **of the nameplate rating** and is expected to last more than 180 calendar days.	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

BC Hydro appreciates drafting team's consideration of our comments to Draft 1's Attachment 1.

In reference to **Section I Items 3 and 4**: While BC Hydro fully understands the potential risk to reliability, and the need to promptly inform the TP and update the data models, BC Hydro maintains the recommendation that the Standard provide an allowance to complete the model verification within up to 12 calendar months for circumstances (including operational and environmental restrictions) that are outside the Facility owner's control.

Section II Item 5: Based on the drafting team responses to our comments to Draft 1 (i.e. "multiple options exist to verify the capability of the Facility"), BC Hydro's understanding is that the Standard allows (per Section II Item 5) the use of, where appropriate, an engineering review as an alternative to staged testing (first bullet) or operational data (second bullet) for model verification. Please confirm if this understanding is accurate.

Section II Bullet 3.1.: BC Hydro's understanding regarding the requirement to create a "simplified one-line diagram representing the Facility" is that the generic example one-line diagram provided in Attachment 2 can be used for all Facilities that fit that diagram (points A, B, C, D, E, F in particular) as determined by the modeling engineer, and this is in line with the drafting team's intent. Please confirm whether this understanding is accurate.

Section II Bullet 6.1.: The language implies that the GO/TO must always use the equipment manufacturer's curve if available. In many cases, however, the manufacturer curve may no longer accurately represent the unit capability, due to various modifications throughout the lifetime of the unit. BC Hydro recommends that the wording be revised to allow for engineering judgment/analysis to be used in determining which available data is best for the capability curve derivation.

Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

Talen supports the comments of the NAGF. Also, MOD-025 should have the same capacity factor exemption as MOD-026 and MOD-027.

Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	

Answer	No
Document Name	
Comment	
Please see the responses to questions 1 and 2.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the MRO NSRF, EEI and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	No
Document Name	
Comment	
The Attachments to MOD-025 include a mix of both actions needed for compliance and optional guidance for how to comply. This mix is confusing for entities who are trying to understand the baseline for compliance, and may also confuse ERO auditors who interpret the examples as required evidence. Tacoma Power recommends moving the examples or guidance of how to comply to either the Technical Rationale or an Implementation Guide.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	

Answer	Yes
Document Name	
Comment	

Section I. 2 leaving 180 days instead of 365 days currently required creates a problem for Wind Generation based on low wind season.

Attachment 1, Sec 3.3: How much time is considered sufficient time to demonstrate the facility can operate at that real and reactive load level?

Attachment 1, NOTE 1: What's the criteria/scope of the required simulation/engineering analysis to determine expected capacity under less restrictive system voltage.

Likes 0	
Dislikes 0	
Response	

James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns

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	

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
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 NPCC RSC	
Answer	
Document Name	
Comment	
Section 1, point 1: “responsible entity” seems to be more commonly used in the Reliability Standards than “applicable entity”. Furthermore, suggest specifying who (the TO?) is responsible to complete the engineering review or analysis. In our opinion, there is no added value to specifying a minimal Facility outage time of 180 days to be allowed to delay from verification. If the entity is unable to verify a Facility because of a planned or unplanned outage, no matter the length of the outage, the entity should be allowed to perform verification within 180 days following its return to service date. Indeed, a minimal outage time of 180 days will actually force the entity to plan its verification on a 9.5-year period, instead of a 10-year period, in order to avoid a situation where an outage of less than 180 days would prevent them from meeting the planned verification date.	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1	
Answer	

Document Name	
Comment	

National Grid supports the concept of developing steady-state composite capability curve (CCC) for the Real Power and Reactive Power.

Additional Comment Regarding Section 4.2 Facilities: Please consider consolidating 4.2.5.1. into 4.2.5. Suggestion: "4.2.5 Voltage source converter (VSC) High-voltage direct current (HVDC) terminal equipment."

Likes 0	
Dislikes 0	
Response	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	
Document Name	
Comment	

ITC - no Comment From response received from Standard Owners or SMEs

Likes 0	
Dislikes 0	
Response	

5. Do you agree the language proposed in MOD-025-3 Attachment 2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Attachments 2 and 3 are written for Generation devices, and because of this, some of the column titles include data which would not be applicable to devices such as FACTS devices. AEP suggests that text be added to the Attachments to clearly indicate that not all data columns will apply to every device in scope. This might be achieved by adding the phrase “only as applicable for a given device” to table headings.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	No
Document Name	
Comment	
In addition to the previous responses to Questions 1 and 4, Tacoma Power recommends ensuring the term "simplified one line" is used consistently throughout the Attachments. The term “one line diagram” is still referenced, and should be changed to “simplified one line”.	
Likes 1	Kelley Tim On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Fou
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports EEI, the MRO NSRF and NAGF comments.	
Likes 0	

Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
BC Hydro's understanding regarding the requirement to create a "simplified one-line diagram representing the Facility" is that the generic example one-line diagram provided in Attachment 2 can be used for all Facilities that fit that diagram (points A, B, C, D, E, F in particular) as determined by the modeling engineer, and this is in line with the drafting team's intent. Please confirm whether this understanding is accurate. BC Hydro noted within the PQ Curve Data Table (template) column 1 row 3 that the Pmax was revised to Pman in this Draft 2. Please clarify whether this is a typo or was intentional, and if so please provide additional clarity on this revision.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
See our response to Question 4.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	

Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The MRO NSRF is not convinced that projects purpose as outlined in the SAR's scope is being met.

SAR Scope:

1. Revisions to MOD-025-2 to ensure that verification activities produce data and information that can be used by Transmission Planners and Planning Coordinators for the purposes of developing accurate and reasonable plant active and reactive capability data (including possibly representation of the "composite capability curve" inclusive of capability and limiters, where applicable).

2. Ensure that each Planning Coordinator and the area Transmission Planners develop requirements for the Planning Coordinator area real and reactive capability data verification

3. Ensure that Generator Owners provide the data specified by the Planning Coordinator and Transmission Planners for the Planning Coordinator area

The MRO NSRF believes data should be provided as specified by the Planning Coordinator and Transmission Planners for the Planning Coordinator area as specified in the SAR scope.

Further, if Attachment 2 were to remain, the MRO NSRF suggests removing the simplified one-line diagram example and all composite capability curve examples from Attachment 2 and placing them in the technical rationale document, as Reliability Standards establish enforceable requirements. Also, the composite capability curves and associated tables need to be labeled in a clearer fashion to ensure associations are not misinterpreted.

Likes 0	
Dislikes 0	

Response

George E Brown - Pattern Operators LP - 5

Answer	No
Document Name	

Comment

Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.

Likes 0	
Dislikes 0	

Response

Deanna Carlson - Cowlitz County PUD - 5

Answer	No
Document Name	

Comment

Cowlitz County PUD No. 1 supports the comments submitted by Tacoma Public Utilites.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	
Comment	

The NAGF recommends that the language for the proposed MOD-025-3 Attachment 1 be revised to address the following:

a. Introduction, 3rd bullet - Recommend that “Documentation showing the engineering basis and verification methodology” should be created by GOs/TOs and left on file if requested by TP. Recommend not making it a mandatory submission to the TP.

b. Section II - See comments on Attachment 1 Section II.6 to II.8 above. CCC should not be a requirement of engineering analysis.

c. Section III - PQ data table should not have rows beyond Pmin and Pmax. Data in between Pmin and Pmax can be reasonably interpolated by TP if required.

Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	
Comment	

AZPS supports the following comments submitted by EEI on behalf of its members:

Section II: Please see EEI’s comments related to the Composite Capability Curve (CCC) under our response to question 5 (Attachment 1, Parts 6-8).

Section II, Figure 2: EEI asks the SDT to align Figure 2 with the BES definition. Figure 2 show a single IBR’s capability curve, but a resource of the size shown would only be applicable if the entire plant’s resources aggregate to a value greater than 75MVA, under inclusion I4 of the BES definition (See BAL-003-3 Applicability Section). Such an example might incorrectly imply to an auditor that registered GOs are responsible for providing capability curves for each individual resources rather than a capability curve that reflects the aggregated plant capability.

Section II, PQ Curve Data Table (template): The data table template should not require data entry beyond Pmin and Pmax. Data in between Pmin and Pmax can be reasonably interpreted by TP if required.

Likes 0	
Dislikes 0	
Response	

Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	

Comment	
Enel supports comments made by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	
- Att 2 Introduction. Recommend “Documentation showing the engineering basis and verification methodology” should be created by GOs/TOs and left on file if requested by TP. Recommend not making it a mandatory submission to the TP. - Att 2 Section II. See comments on Att 1 Section II.6-8. CCC should not be a requirement of engineering analysis. - Att 2 Section III. PQ data table should not have rows beyond Pmin and Pmax. Data in between Pmin and Pmax can be reasonably interpolated by TP if required. - The PC/TP needs to have a say in the verification data requirements as indicated by the SAR Project Scope. - There is an error in the PQ Curve data table on page 21 of the clean -3 draft: The 2nd column title should be P (MW) rather than Pmax (MW).	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM supports EEI's recommended changes to Attachment 2.	
Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	No

Document Name	
Comment	
Entergy recommends that the language for the proposed MOD-025-3 Attachment 2 be revised to address the following: 1. T. Planning needs a CCC. We may run studies at different MW output levels than what the GO determines to be Pmax and Pmin and we also need other limits plotted on the curve like OEL. 2. Section III- PQ data table should not have rows beyond Pmin and Pmax. This information is already provided in composite capability curve and not needed to be repeated.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC signed on to ACES comments below: The PQ Curve Data Table (template) indicates that Range = (Pman – Pmin). This change from the previous value of Pmax is not clear. Please provide a definition of what Pman is intended to represent.	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comemnts of the Edison Electric Institute (EEI) to questions #5.	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
NPPD supports comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation agrees with comments made by NAGF. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the NAGF comments	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No

Document Name	
Comment	
Black Hills Corporation supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports Midwest Reliability Organization’s NERC Standards Review Forum’s (MRO NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
Further clarity on aux load definition is needed; aux load less than 1% that supports unit output should not be required to be included in the calculation (as it relates to points D and E on the diagram).	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment	
EEI offers the following recommended changes to Attachment 2: Section II: Please see EEI's comments related to the Composite Capability Curve (CCC) under our response to question 5 (Attachment 1, Parts 6-8). Section II, Figure 2: Align Figure 2 with the BES definition. Figure 2 shows a single IBR's capability curve, but a resource of the size shown would only be applicable if the entire plant's resources aggregate to a value greater than 75MVA, under inclusion I4 of the BES definition (See BAL-003-3 Applicability Section). Such an example might incorrectly imply to an auditor that registered GOs are responsible for providing capability curves for each individual resources rather than a capability curve that reflects the aggregated plant capability. Section II, PQ Curve Data Table (template): The data table template should not require data entry beyond Pmin and Pmax. Data in between Pmin and Pmax can be reasonably interpreted by TP if required.	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation agrees with comments made by NAGF. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI is supportive of the comments provided by the NAGF.	
Likes 0	
Dislikes 0	

Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
We would like clarification on how they came up with the composite capability curve and the PQ data table in Attachment 2.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Section II.7.2 and III.4 require the representation of "all" auxiliary equipment. There should be realistic limits to the size of an auxiliary sources that are required for reporting. If a separate auxiliary source connection (Point E, Station Service Transformer) provide load less than 0.5% of Pmax, reporting of auxiliary load should be excluded. In addition, the engineering analysis option requirement needs to have better tighter criteria /guidance around it so that it would be consistent subject to acceptance criteria. Finally, criteria for the TO should also be included for operational /staged testing and these parties held accountable for the test preparation and test conditions that will allow generators to be able to better meet their true capability limits.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	

PG&E does not support the proposed modifications and is in alignment with the Edison Electric Institute (EEI) recommended modifications.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
The PQ Curve Data Table (template) indicates that Range = (Pman – Pmin). This change from the previous value of Pmax is not clear. Please provide a definition of what Pman is intended to represent.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Proposed Attachments 1, 2 and 3 include excessive data collection and engineering efforts that will most likely require contracted testing engineering and do not provide useful information to the Transmission Planner comparable to the effort and cost that will be required to perform the work.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	

Pmax, Pmin, Qmax, and Qmin results are not adequate to be used in the models.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	

Comment

The PQ data table required will add additional MW points where Qmax and Qmin need to be determine. These additional steps will add additional test time.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	Yes
Document Name	

Comment

We support RSC comments

Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
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	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC - no Comment From response received from Standard Owners or SMEs	
Likes 0	
Dislikes 0	
Response	

6. Do you agree the language proposed in MOD-025-3 Attachment 3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Proposed Attachments 1, 2 and 3 include excessive data collection and engineering efforts that will most likely require contracted testing engineering and do not provide useful information to the Transmission Planner comparable to the effort and cost that will be required to perform the work.	
Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E is in agreement with the input from the Edison Electric Institute (EEI) on the whether the data requirements of Attachment 3 are duplicative of those in MOD-032 and if they are duplicative, they should be removed.	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Section II.7.2 and III.4 require the representation of "all" auxiliary equipment. There should be realistic limits to the size of an auxiliary sources that are required for reporting. If a separate auxiliary source connection (Point E, Station Service Transformer) provide load less than 0.5% of Pmax, reporting of auxiliary load should be excluded. In addition, the engineering analysis option requirement needs to have better tighter criteria /guidance around it so that it would be consistent subject to	

acceptance criteria.

Finally, criteria for the TO should also be included for operational /staged testing and these parties held accountable for the test preparation and test conditions that will allow generators to be able to better meet their true capability limits.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	

Comment

AECI is supportive of the comments provided by the NAGF.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation agrees with comments made by NAGF.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

The data requirements of Attachment 3 appear duplicative of those in MOD-032. If they are duplicative, they should be removed from Attachment 3 prior to the next draft of MOD-025 or explain why they are needed within both MOD-032 and MOD-025.

Likes 0	
Dislikes 0	

Response
Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	No
Document Name	

Comment
Further clarity on aux load definition is needed; aux load less than 1% that supports unit output should not be required to be included in the calculation (as it relates to points D and E on the diagram).

Likes 0	
Dislikes 0	

Response
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez

Answer	No
Document Name	

Comment
SRP supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.

Likes 0	
Dislikes 0	

Response
Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

Black Hills Corporation supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI's comments.	

Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation agrees with comments made by NAGF. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
NPPD supports comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comemnts of the Edison Electric Institute (EEI) to questions #6.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

MPC supports MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	

Response

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

The PC/TP needs to have a say in the verification data requirements as indicated by the SAR Project Scope.

Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Enel supports comments made by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS supports the following comments submitted by EEI on behalf of its members: EEI questions whether the data requirements of Attachment 3 are duplicative of those in MOD-032. If they are in fact, duplicative, they should be removed from Attachment 3 prior to the next draft of MOD-025, or explain why they are needed within both MOD-032 and MOD-025.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF notes that the same data may already be available via MOD-032.	

Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	

Response

George E Brown - Pattern Operators LP - 5

Answer	No
Document Name	

Comment

Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.

Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The MRO NSRF is not convinced that projects purpose as outlined in the SAR's scope is being met.

SAR Scope:

4. Revisions to MOD-025-2 to ensure that verification activities produce data and information that can be used by Transmission Planners and Planning Coordinators for the purposes of developing accurate and reasonable plant active and reactive capability data (including possibly representation of the "composite capability curve" inclusive of capability and limiters, where applicable).

5. Ensure that each Planning Coordinator and the area Transmission Planners develop requirements for the Planning Coordinator area real and reactive capability data verification

6. Ensure that Generator Owners provide the data specified by the Planning Coordinator and Transmission Planners for the Planning Coordinator area

The MRO NSRF believes data should be provided as specified by the Planning Coordinator and Transmission Planners for the Planning Coordinator area as specified in the SAR scope.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

The summary of test/operational data has added additional data requirements for nameplate data which can be captured or is required under VAR-002 or MOD-032. Does this language create re-work and duplication of efforts for limited personnel/resources, versus simplifying? Is it understood that some information is not able to be ‘verified’ during unit operation? Examples could be: (a) transformer tap changer settings which are located on top of transformers or inside enclosures - Is it acceptable to document ‘unable to verify’? and (b) Is there guidance on leaving blanks or documenting as N/A?

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FE supports EEI’s comments which state:

EEI does not agree with the data requirements of Attachment 3 because they appear to be duplicative of those in MOD-032.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment	
Talen supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the MRO NSRF and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Please see response to Question #5.	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	

We support RSC comments	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports the language contained in Attachment 3.	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz County PUD No. 1, 5, 6/7/2023	
Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
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	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC - no Comment From response received from Standard Owners or SMEs	
Likes 0	
Dislikes 0	
Response	

7. The SDT believes the language of MOD-025-3 addresses the issues outlined in the two SARs in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group supports the MRO NSRF and the NAGF comments.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

It put un-necessary burden on Generator Owner, Transmission Owner and Transmission Planner, which is detrimental to system reliability. The verification process should be simplified and adding more description to the process may not translate to more accuracy in the modeling. It significantly increases compliance costs with a minimum improvement in reliability. The proposed verification process requires significant time, expertise, and difficulty in obtaining some of the required information for the older plant (which may increase the risk of noon compliance). Most likely will put a lot of burden on the generation and transmission owners in preparing this documentation and analysis at the same time the burden of planners reviewing this documentation may not address their concerns and this documentation may not be used by planners for modeling purposes.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

Talen supports the comments of the NAGF. Also, there is no cost effectiveness if TPs discard the GO's calculations and use only as-measured VAR

test results.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Until the DT provides clarification and guidance, FirstEnergy cannot determine the scope of this standard in a cost effective manner.	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The MRO NSRF is not convinced that projects purpose as outlined in the SAR's scope is being met, please see comments to questions one, two, three, four, five & six.	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.	

Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach. In addition, it is unclear if a staged test is still mandatory. If so, testing at additional load points (20%, 40%, 60%, 80%) will increase testing times for limited value. This increase in testing times will affect how units are offered in to the system as well as contractor testing costs for those entities that do not have the in-house plant expertise to test.	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS generally agrees that the language of MOD-025-3 addresses the issues outlined in the two SARs in a cost effective manner. However, AZPS does not agree that the proposed implementation plan related to MOD-025-3 is cost effective as it accelerates the periodicity time frames currently established under MOD-025-2 which will result in additional verifications within the first three years.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Enel supports comments made by the MRO NSRF.	

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC

Answer	No
Document Name	

Comment

- The SAR makes reference to the need to produce data that can be used ty the TP and PC and for the need for these two entities to verify data, however, the PC is not added as a recipient of the data in the proposed standard.
- Item 2 in the Project Scope section is not addressed in the proposed revision. That item seems to already be provided for in MOD-032.
- It is not clear how this proposed standard revision aligns MOD-025 with MOD-032 as stated in #7 in the Project Scope section. The proposal does not include data being provided to the PC as is provided for in MOD-032.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

In the Project Scope section of the SAR, the PC/TP are to develop real and reactive capability requirements and data provision specifications, but there is no requirement in the proposed draft to have them do so. See these two items in that section:

- "2. Ensure that each Planning Coordinator and the area Transmission Planners develop requirements for the Planning Coordinator area real and reactive capability data verification."
- "3. Ensure that Generator Owners provide the data specified by the Planning Coordinator and Transmission Planners for the Planning Coordinator area."

Likes 0	
Dislikes 0	

Response

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment	
Additionally, it is unclear if a staged test is still mandatory. If so, testing at additional load points (20%, 40%, 60%, 80%) will increase testing times for limited value. This increase in testing times will affect how units are offered in to the system as well as contractor testing costs for those entities that do not have the in-house plant expertise to test.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC sees additional opportunity to address the issues outlined in the two SARs and additional opportunity to improve the cost effectiveness of the approach. If the purpose of MOD-025 is to "ensure that accurate information on Bulk Electric System (BES) Facility Real and Reactive Power capability is available for planning models used to assess BES Reliability," then more attention needs to be given to what information is needed by the modeling party. The proposed changes do not ensure that the final consumer of the information is receiving what they need because the current standard does not include a provision for how an entity is to request information from the GO/TO.	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
NPPD supports comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation believes that these changes will be extremely cost burdensome to the Generator Owner due to the change to the forms and required data that needs to be collected and documented, condensed time frame to provide data to the Transmission Planner, condensed timeframe for data to be provided and potential need to hire external resources (contractors) to meet the additional data prescribed. In addition, as previously mentioned in the response to other questions above, this new draft does not change any of the existing testing periodicities or data currently imposed by the Transmission Planners. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP disagrees with changing verification period from 90 days to 30. The cost to change from 90 days to 30 is unknown.	
Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
Most MOD-025 test reports submitted to date have not been reviewed or used by the TPs or ISOs. Generator Owners have consistently seen this in different regions. ISOs mandate their own criteria for capability testing, rendering the standard ineffective. The drafting team should research the different ISO capability test requirements and establish a common method to determine Real and Reactive Power capability or remove MOD-025.	
Likes 0	

Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation believes that these changes will be extremely cost burdensome to the Generator Owner due to the change to the forms and required data that needs to be collected and documented, condensed time frame to provide data to the Transmission Planner, condensed timeframe for data to be provided and potential need to hire external resources (contractors) to meet the additional data prescribed. In addition, as previously mentioned in the response to other questions above, this new draft does not change any of the existing testing periodicities or data currently imposed by the Transmission Planners. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI is supportive of the comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Submitted MOD-025 test reports to date have not been reviewed or used by the TPs or ISOs. Generator Owners have consistently seen this in different regions. ISOs mandate their own criteria for capability testing, rendering the standard ineffective. The drafting team should research the different ISO	

capability test requirements and establish a common method to determine Real and Reactive Power capability or remove MOD-025.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
This draft of the standard still does not serve the intended purpose of the standard and does not justify the added costs.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
The data collected and its use does not justify the cost of testing or documentation creation/retention.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	
We support RSC comments	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns	
Answer	Yes
Document Name	
Comment	
The only potential concern would be reliance on strictly engineering analysis for the verification. Some tie to test results (Pmax testing, De Mello zero-power factor load rejection) should be used.	
Likes 0	
Dislikes 0	

Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
The IRC SRC agrees that applicable entities may incur cost to comply with MOD-025, however, the cost is warranted as the need for operational capability data is very important for accurate modeling purposes and ultimately the reliable operation of the BES.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	
Document Name	
Comment	
N/A Deanna Carlson, Cowlitz County PUD No. 1, 5, 6/7/2023	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	
Document Name	
Comment	

Minnesota Power will not be providing comments on cost-effectiveness at this time.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	
Document Name	

Comment

Black Hills Corporation will not provide comment on cost-effectiveness.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	
Document Name	

Comment

Black Hills Corporation will not provide comment for cost-effectiveness.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	
Document Name	

Comment

Black Hills Corporation will not provide comment on cost-effectiveness.

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	
Document Name	

Comment

ITC - no Comment From response received from Standard Owners or SMEs

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment

No comment.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	
Document Name	

Comment

At this time PG&E has not been able to complete a cost analysis on the impact of the modifications.

Likes 0	
Dislikes 0	

Response

8. The SDT proposes a 1-year implementation plan for MOD-025-3 Requirements R3 and R4, with an additional 2 years (3 years total) for compliance with Requirements R1 and R2. For Requirements R1 and R2 with reoccurring periodicity for existing Facilities, the Implementation Plan proposes applicable entities shall initially comply within 66 calendar months of their last performance under the respective requirements of MOD-025-2 (Requirement R1, R2, and R3). Would these proposed timeframes give enough time to put into place process, procedures or technology to meet the proposed language? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

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

Answer	No
Document Name	

Comment

We still find the implementation plan to be confusing as written. Perhaps a timeline could be added (see the implementation plan for TPL-001-5 as an example – Project 2015-10). For newly commissioned GO facilities, we interpret the draft implementation plan to require verifications performed pursuant to MOD-025-3 R1 / Attachment 1 to begin on the effective date, but the evidence would not be subject to audit until the R1 effective date 24 months later? For existing GO facilities that are subject to MOD-025-2, any facility that reaches its 66 month (or longer) anniversary date between the effective date and the R1 compliance date (a 24 month span) would need evidence that a MOD-025-3 R1 verification was completed during the 24 month window, otherwise the GO would file a self-report for any existing facility that this was not achieved for on the R1 compliance date? Upon the R1 compliance date, existing facilities that were subject to MOD-025-2, and were not MOD-025-3 R1 verified within the 24 month span between the effective date and R1 compliance date, will be subject to the 66 month from their last MOD-025-2 verification rule? Does this essentially provide a 90 month window to implement R1 beginning on the effective date, with compliance enforcement kicking in at 24 months?

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PG&E supports the input provided by the Edison Electric Institute (EEI) on not supporting the modifications and the EEI input on the performance of initial periodic requirements.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	No
Document Name	
Comment	

According to the Initial Performance of Periodic Requirements within the implementation plan, existing entities shall comply within 66 calendar months from last performance for next test under V3. Additionally, if the timeframe for existing units to perform testing falls between the effective date of the standard and the compliance date, the applicable entity shall comply by the Compliance date. However, this is confusing as existing resources that have been tested close to the new effective date under Version 2 may exceed the 2 year compliance date for the next iteration of testing allowed (66 months). This is not clear.

It would be better to start the compliance date unilaterally for existing and new applicable units under all requirements to avoid confusion. In this way, test results performed under the new requirements would also be properly reviewed by the Transmission Planner under R3 and R4.

Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	
Comment	

We believe that agreement with the implementation plan is dependent on the clarification mentioned in the comment for R1 and R2.

Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	
Comment	

AECI is supportive of the comments provided by the NAGF.

Likes 0	
Dislikes 0	

Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation feels there is still confusion on timelines based on internal industry discussions. It is unclear on when the timelines for the new standard obligations take effect whether it is at your periodic cycle or upon effective date. Without clear interpretation it is difficult for Generator Owners to plan appropriately to meet compliance with requirement. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support the proposed staged implementation plan. Requirements 1 and 2 provide GOs and TOs three years before they are obligated to comply with these Requirements. However, there is no meaningful work that a TP could do under Requirement R3 until the responsible GOs and TOs have completed their verification testing and submittals under Requirement R1 and R2. Additionally, GOs and TOs will not receive any notifications of technical concern until after obligations under Requirement R1 and R2 are sent to the TP under Requirement R3, meaning no work can be done under R4 until R1, R2 and R3 tests, submissions, and reviews are completed. For this reason, all Requirements in MOD-025-3 should become effective at the same time (i.e., 3 years after approval of the Reliability Standard). Relative to the Initial Performance of Periodic Requirements, EEI supports the plan to require applicable entities to initially comply with Requirements 1 and 2 within 66 calendar months of their last performance under the respective requirements in MOD-025-2.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	

Comment

According to the Initial Performance of Periodic Requirements within the implementation plan, existing entities shall comply within 66 calendar months from last performance for next test under V3. Additionally, if the timeframe for existing units to perform testing falls between the effective date of the standard and the compliance date, the applicable entity shall comply by the Compliance date. However, this is confusing as existing resources that have been tested close to the new effective date under Version 2 may exceed the 2 year compliance date for the next iteration of testing allowed (66 months). This is not clear.

It would be better to start the compliance date unilaterally for existing and new applicable units under all requirements to avoid confusion. In this way, test results performed under the new requirements would also be properly reviewed by the Transmission Planner under R3 and R4.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez

Answer	No
Document Name	

Comment

The valid testing agencies are hard to schedule as it is. If you mandate that all of the units are tested in a year, there will be backlog on the side of the vendors and the TPs will be hard pressed to keep up with the 90-day validations.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

Black Hills Corporation supports the NAGF comments.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation feels there is still confusion on timelines based on internal industry discussions. It is unclear on when the timelines for the new standard obligations take effect whether it is at your periodic cycle or upon effective date. Without clear interpretation it is difficult for Generator Owners to plan appropriately to meet compliance with requirement. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
NPPD suggests the implementation be phased in a manner similar to the original implementation of MOD-025, so that not all units will be become compliant with the Standard at the same time. An enforcement date that includes 100% of applicable facilities could result in an tidal wave of work that may overwhelm entities.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO does not believe that 24 months after approval of the standard to perform real/reactive power engineering analysis of all units in scope is sufficient, and believes the implementation of R1 and R2 should be 60 months after the effective date considering the detailed analysis.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comemnts of the Edison Electric Institute (EEI) to questions #8.	
Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
• It should be phase in implementation either a 5-year implementation period or allow updates based upon current MOD-025 testing plans.	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM supports with EEI comments.	
Likes 0	
Dislikes 0	
Response	

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Per this implementation plan, a GO will have 2 years after approval of the standard to perform real/reactive power engineering analysis of all units in scope. We do not believe this is a sufficient window of time for such a large undertaking. Considering most standards requiring detailed analysis have a 5-year phase in period, we believe 5 years of phase-in should be the minimum time allotted.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

AZPS supports the following comments submitted by EEI on behalf of its members:

EEI does not support the proposed staged implementation plan. Requirements 1 and 2 provide GOs and TOs three years before they are obligated to comply with these Requirements. However, there is no meaningful work that a TP could do under Requirement R3 until the responsible GOs and TOs have completed their verification testing and submittals under Requirement R1 and R2. Additionally, GOs and TOs will not receive any notifications of technical concern until after obligations under Requirement R1 and R2 are sent to the TP under Requirement R3, meaning no work can be done under R4 until R1, R2 and R3 tests, submissions, and reviews are completed. For this reason, all Requirements in MOD-025-3 should become effective at the same time (i.e., 3 years after approval of the Reliability Standard). Relative to the Initial Performance of Periodic Requirements, EEI supports the plan to require applicable entities to initially comply with Requirements 1 and 2 within 66 calendar months of their last performance under the respective requirements in MOD-025-2.

Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

Per the proposed MOD-025-3 implementation plan, the NAGF notes that a GO will have 2 years after approval of the standard to perform real/reactive power engineering analysis of all its units in scope. We do not believe this is a sufficient window of time for such a large undertaking. Considering most standards requiring detailed analysis have a 5-year phase in period, we believe 5 years of phase-in should be the minimum time allotted.

In addition, the NAGF recommends that an example timeline be included given the different timeframes identified in the proposed MOD-025-3 implementation plan.

Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	

Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	No
Document Name	

Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
The implementation plan doesn’t provide GOs sufficient time for such an enormous effort. The time required to review, modify existing processes and procedures, and perform the recommended analyses for all units in scope will require a longer phase-in. Duke Energy recommends a 2-year implementation plan for MOD-025-3 Requirements R3 and R4, with an additional 3 years (5 years total) for compliance with Requirements R1 and R2.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy recommends coordinating the Implementation of R3 and R4 with R1 and R2's implementation and further suggest a 24-month implementation to ensure sufficient time for the GO and/or the TO to verify the data needed under this standard.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

Talen supports the comments of the NAGF.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group supports the NAGF and EEI comments.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	Yes
Document Name	

Comment

We support RSC comments

Likes 0	
Dislikes 0	

Response

Deanna Carlson - Cowlitz County PUD - 5

Answer	Yes
Document Name	

Comment

Deanna Carlson, Cowlitz County PUD No. 1, 5, 6/7/2023

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
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	

Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC - no Comment From response received from Standard Owners or SMEs	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	

9. Do you agree the language proposed in PRC-019-3 Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

"Protective functions" would likely include embedded systems which infers an understanding of the decision trees and logical operators of every device in scope. This level of understanding may only be fully grasped by the manufacturers themselves, and may also include proprietary information that the OEMs may not wish to share. This puts the TO and GO at risk for having an understanding of the underlying logic that may be fully grasped or known only by the manufacturers themselves, and obtaining this information from the OEM has already proven to be very difficult in practice.

AEP disagrees with the removal of "or stability limits" from R1.1.2., which seems to be driven from the text within the SAR which states "Manual SSSL theory is only applicable when a generator AVR is in manual operation mode" which we disagree with as well. *The author seems to incorrectly assume that the SSSL is always outside the thermal capability curve, which is not correct.*

Regarding the SDT's response in their previous consideration of comments document, where they state "The SDT believes that the scope for coordination requirements are limited to the functions and capabilities described in the standard or in industry guidance within Section E." AEP believes that care should be taken to ensure that all scope, function and capability limitations are clearly provided within the standard itself, and that no important content is perhaps provided only within the external "associated documents" of Section E.

Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

WEC Energy Group supports the MRO NSRF and the NAGF comments.

Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	No

Document Name	
Comment	

Manitoba Hydro agrees with the removal of stability limits however, MH recommends further wording changes for R1 and to remove “equipment capabilities “as a requirement of the control and protection coordination.

Manitoba Hydro agrees with that a coordination of control and protection elements should take place if equipment capabilities change and should be plotted (if known) as part of Attachment 1; however, the standard should focus on control and protection coordination.

Manitoba Hydro would also like to have the standard reflect how to handle instances when the equipment capabilities are not known, such as volts per hertz limitations for older generators? Clear definitions and operating ranges need to be provided for equipment capabilities in Appendix A.

Manitoba Hydro grees with the removal of the 5/6 year window and the removal of the steady state limit.

manitoba Hydro has no issues with going back to the original use of “Protection System” which will include protection functions that reside in control devices.

Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

Talen supports the comments of the NAGF.

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

While we support EEI's comments, FirstEnergy also request clarification on if the coordination for Requirement 1 would be required of individual IBR units.

Likes 0	

Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	
WECC has concerns with footnotes containing the word "shall." This language should be reserved for Requirements. WECC also believes it is unwise to use the IEEE definition of IBR resourse. There are references in the definition that provide exemptions. IBR Resourse depends on the IEEE defintion of "IBR Unit" which depends on the capability and performance of "type testing" the device. This complex linkage of definitions in the IEEE standard could have the potential of removing inverters that are not type tested or satisfactorily type tested from applicability of the standard. WECC encourages the SDT and NERC to work on clearly defining what is meant by IBR resource as used in the standard.	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC Generator Working Group: the standard should not mix control and protection coordination. Control functions in power plant controllers and IBR units are often proprietary and not always easiliy obtainable. The term "control functions" may be to broad of an expression that may leave companies falling out of compliance for subjective reasons. Suggest wording to be changed to "if any limiters are programmed in these control devices, the equipment should be limited before it trips"	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	

Comment	
Pattern Energy supports Midwest Reliability Organization’s NERC Standards Review Forum’s (MRO NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The MRO NSRF does not agree with Requirement R1 language, which is defined in §4. Applicability of the proposed standard.

§4.2.4 Inverter-based resource (IBR) generating plant/Facility greater than 75

MVA (gross nameplate rating) including:

4.2.4.1 Individual IBR units;

4.2.4.2 Collector bus(es) and collector feeder(s);

4.2.4.3 Static or dynamic reactive compensating devices;

4.2.4.4 Main power transformer (MPT);1

4.2.4.5 Generator step-up (GSU) transformer(s);2

Inverter-based resource (IBR) is not a defined term. Using undefined terms that are subject to interpretation is not an acceptable practice in a ‘zero-defect’ enforcement environment. For example, on March 28, 2023, NERC released a recap of technical session’s Inverter-Based Resource Panel. In this panel’s Quick Reference Guide (https://www.nerc.com/pa/Documents/IBR_Quick%20Reference%20Guide.pdf) a definition is outlined for IBR as follows:

In most cases, inverter-based generating resources refer to Type 3 and Type 4 wind power plants and solar photovoltaic (PV) resources. Battery energy storage is also considered an inverter-based resource. Many transmission-connected reactive devices, such as STATCOMs and SVCs, are also inverter-based. Similarly, HVDC circuits also interface with the ac network though converters. Inverter-based resources are being interconnected at the bulk power system (BPS) level as well as at the distribution level; however, this reference guide focuses specifically on BPS-connected inverter-based resource efforts.

If a responsible entity were to define IBR using the aforementioned definition and exclude Type I & II wind turbine generators is this the intention of the SDT?

Further, footnote 1 of Requirement R1, states that IBR unit is defined by IEEE Std. 2800. It is not acceptable to define a term using an external source that is not subject to the NERC Rules of Procedure. Second, IEEE Std. 2800 is not a public document.

The MRO NSRF disagrees with the use of the term “control functions”. This standard should not mix control and protection “coordination.” Control functions in power plant controllers are often proprietary and not always obtainable. Furthermore, the term “control functions” is a broad expression that will leave GOs/TOs susceptible to falling out of compliance on a subjective basis. Wording should be revised that if any limiters are programmed in these control devices, the equipment should limit before it trips.

Finally, Requirement R1 states the following, “Equipment capabilities, control functions, and protective functions for the applicable Facilities include, but are not limited to those listed in

Attachment 1.” The MRO NSRF disagrees with “include, but are not limited to those listed in Attachment 1” language as it is open ended and subject to interpretation by both responsible entities and enforcement authorities. The MRO NSRF suggests the language is changed to “Equipment capabilities, control functions, and protective functions for the applicable Facilities are those listed in Attachment 1.”

Likes 2	Lincoln Electric System, 5, Millard Brittany; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF notes that Requirements R1 1.2.1 & 1.2.2 should not mix control and protection “coordination.” Control functions in Power Plant Controllers (PPC) and Inverter-Based Resources (IBR) units are often proprietary and not always easily obtainable. Furthermore, the term “control functions” is a broad expression that will leave GOs/TOs susceptible to falling out of compliance on a subjective basis. Recommend that the wording be revised such that “*if any limiters are programmed in these control devices, the equipment should limit before it trips.”*

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

AZPS supports the following comments submitted by EEI on behalf of its members:

Comments: EEI does not support the proposed language in PRC-019-3, Requirement R1 because the last sentence in Requirement R1 is open ended and without limits and needs to be removed. (i.e., "but are not limited to those listed in Attachment 1") Such a statement does not conform to a NERC Results Based Reliability Standard. To address this concern, we ask the SDT to remove this language. (See below)

R1. Each Generator Owner and Transmission Owner with applicable Facilities Shall Coordinate the voltage and regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. Equipment capabilities, control functions, and protection functions for the applicable Facilities include**, but are not limited to those listed in Attachment 1**.

We are also concerned that the language contained in parts 1.2.1 & 1.2.2, where control and protection is intermingled, creates ambiguity for entities regarding what is exactly intended. We are also concerned that this Reliability Standard inappropriately mixes control and protection "coordination." Control functions in Power Plant Controllers and IBR units are often proprietary and not always easily obtainable by protection engineers. We further note that the term "control functions" is a broad expression that will leave GOs/TOs susceptible to falling out of compliance on a subjective basis. For this reason, we ask the SDT to develop a definition for control functions to address this concern either within PRC-019 or more broadly within the NERC Glossary of Terms.

Consideration should also be given to revising language within R1 (parts 1.2.1 & 1.2.2) to make it clear that if any limiters are programmed in these control devices, the equipment should limit before it trips.

Likes 0	
Dislikes 0	
Response	

Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	

Enel supports comments made by the MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	
Comment	

Section B, R1 1.2.1 & 1.2.2: This standard should not mix control and protection “coordination.” Control functions in Power Plant Controllers and IBR units are often proprietary and not always easily obtainable. Furthermore, the term “control functions” is a broad expression that will leave GOs/TOs susceptible to falling out of compliance on a subjective basis. Wording should be revised that if any limiters are programmed in these control devices, the equipment should limit before it trips.

Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC

Answer	No
Document Name	
Comment	

None

Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	
Comment	

MPC supports MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comemnts of the Edison Electric Institute (EEI) to questions #9.	
Likes 0	
Dislikes 0	
Response	

Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
NPPD supports comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation has concerns on the scope of protective function as it is not a defined term, this could inadvertently expand the scope of PRC-019. Constellation recognizes it is explained in Attachment 1 but suggests a definition should be made. Constellation further agrees with NAGF comments on coordination requirements. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum (NSRF) comments	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP prefers IBR's have their own set of standards versus incorporating them into current standards.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI does not support the proposed language in PRC-019-3, Requirement R1 because the last sentence in Requirement R1 is open ended and without limits and needs to be removed. (i.e., "but are not limited to those listed in Attachment 1") Such a statement does not conform to a NERC Results Based Reliability Standard. To address this concern, we ask the SDT to remove this language. (See below)

R1. Each Generator Owner and Transmission Owner with applicable Facilities Shall Coordinate the voltage and regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. Equipment capabilities, control functions, and protection functions for the applicable Facilities include**:**

The language contained in parts 1.2.1 & 1.2.2, where control and protection is intermingled, creates ambiguity for entities regarding what is exactly intended. Also this Reliability Standard inappropriately mixes control and protection "coordination." Control functions in Power Plant Controllers and IBR units are often proprietary and not always easily obtainable by protection engineers. Additionally, the term "control functions" is a broad expression that will leave GOs/TOs susceptible to falling out of compliance on a subjective basis. For this reason, the SDT should develop a definition for control functions to address this concern either within PRC-019 or more broadly within the NERC Glossary of Terms.

Consideration should also be given to revising language within R1 (parts 1.2.1 & 1.2.2) to make it clear that if any limiters are programmed in these control devices, the equipment should limit before it trips.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation has concerns on the scope of protective function as it is not a defined term, this could inadvertently expand the scope of PRC-019. Constellation recognizes it is explained in Attachment 1 but suggests a definition should be made. Constellation further agrees with NAGF comments on coordination requirements.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	

Comment

AECI is supportive of the comments provided by the NAGF.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	
Comment	

Rather than using Footnote 6, Ameren suggests creating a NERC defined term of inverter-based resources. The definition should also be included in the standard. Please clarify Section 1.2 and what should be done if voltage control mode is not used. Ameren also has concern with the phrase "but are not limited to those listed in attachment 1" because an IBR manufacturer may have a control function that acts like a limiter but they will say no when asked if they have a limiter.

Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC

Answer	No
Document Name	
Comment	

SMUD and BANC disagree with the language proposed in PRC-019-3 Requirement R1 because the term Inverter-based Resource (IBR) is not adequately defined. The Standards Drafting Team (SDT) should create a formal definition and not attempt to define it in the Applicability section. The reference to IEEE Std. 2800 in footnote 6 to define an "IBR unit" should also be avoided as IEEE Standards are not free to registered entities and could be changed by the IEEE at any time, outside of the NERC Standards development process. NERC Project 2022-02 is creating a formal definition for Distributed Energy Resource (DER), so it makes sense that the term IBR also be defined.

In addition, footnotes in standards should not be used to include part of the requirement to meet compliance. Specifically in Requirement R1: " Each Generator Owner and Transmission Owner with applicable Facilities shall coordinate[3] the voltage regulating system controls, …" and footnote 3 in R1: "Protection System as-left settings shall be utilized in compliance evidence for a protection and control coordination study." If something shall be used for compliance evidence, it should be in the main body of the Standard Requirement and not hidden in the footnotes.

Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	No
Document Name	
Comment	

Revise 1.1.2. wording to the following: “The applicable in-service protective functions are set to operate to isolate or de-energize equipment to prevent damage or limit the extent of damage when operating conditions exceed equipment capabilities.”

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

Coordination should be more specifically defined so that entities are able to achieve what the SDT is looking for. It is unclear what the SDT is expecting for coordination between the control functions and protective functions, as well as considering how the protective functions monitor different physical locations within a plant. Documentation on how to perform the coordination and what is expected must be developed in the industry before it is reasonable to expect entities to comply. Presently, this documentation does not exist.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	Yes
Document Name	

Comment

None.	
Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz County PUD No. 1, 5, 6/7/2023	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports the changes proposed in PRC-019-3, Requirement R1.	

Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	
We support RSC comments	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E supports the input from the Edison Electric Institute (EEI) related to the open ended structure of Requirement R1 and the concerns related to Parts 1.2.1 and 1.2.2 and their recommendation to create a definition for control functions.	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
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	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	

Comment	
ITC - no Comment From response received from Standard Owners or SMEs	
Likes 0	
Dislikes 0	
Response	

10. Do you agree the language proposed in PRC-019-3 Requirement R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	No
Document Name	
Comment	
As indicated in the IRC SRC comments on Draft 1, the associated coordination documentation should be updated ***prior*** to a return to service, ***not within 90 days after*** a return to service. It seems impossible to make coordinated changes prior to implementation of systems without appropriate documentation and coordination studies.	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
We prefer language similar to PRC-019-2, R2 – "Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination….". Not allowing an entity to correct "identified" miscoordination or errors significantly increases non-compliance risk. What is the purpose of the 90-day limit after return-to-service (RTS) to update associated coordination documentation? Per the Technical Rationale "this 90 calendar day period allows time for documentation to be updated for minor discrepancies in firmware, settings or equipment changes that do not	

result in a miscoordination“ but “entities are still required to perform a coordination study in accordance with R1 prior to the implementation of these changes.” If a PRC-019 coordination study is still required, what difference does it make whether the updates are performed within the 90 calendar days after RTS or beyond that timeframe? Or is this 90-day limit actually a 90-day allowance to correct as-left vs. as-studied discrepancies post-implementation? If so, please make this distinction clear since Requirement R2 seems to suggest that there is a 90-day limit to make any setting changes.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
How will entities verify that changes will NOT affect the coordination? While the intent of this language identified in the April 2023 PRC-019-3 Technical Rationale document is laudable, the current verbiage seems to require that the GO/TO "prove the negative". We suggest modifying the language in R2 as follows: "Each Generator Owner and Transmission Owner shall review the coordination described in Requirement R1 prior to implementation of systems, equipment, or settings changes that could affect the coordination described in Requirement R1. If changes are identified that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1 prior to implementation.” While this proposed modification may seem minor on the surface, we believe that it allows greater flexibility for the entity when reviewing changes that may impact coordination while also meeting the stated intent of the SDT. In other words, we believe that the current verbiage necessitates that the entity attempt to "prove the negative" by generating evidence "that a particular change made to systems, equipment, or settings will not affect the coordination". Whereas we believe that the verbiage we proposed will only require evidence that the entity perform a coordination study whenever an impact to coordination is identified.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	

: PG&E is in agreement with the input from the Edison Electric Institute (EEI) that the Requirement R2 language is opened ended and their suggest modifications to address this.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	

Comment

AECI is supportive of the comments provided by the NAGF.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation does not agree with the expanded scope as it will essentially double the work as the Generator Owner will now need to perform a coordination study prior to syncing to grid and then perform a second coordination study following commissioning testing (following tuning). It is impractical to install or reprogram a relay or AVR, identify the as-left settings, then wait a month or two before restarting the unit to have a contractor re-perform or update the PRC-019 study. PRC-019 should provide latitude for the coordination study based on analysis of intended settings, then allow for issuance of a revised report within 90 days of implementation if there are any deviations between intended and as-left settings identified.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No

Document Name	

Comment

EEI does not support the current open ended language (i.e., "but are not limited to those listed below") used in Requirement R2. Additionally, the language in Requirement R2 should be clearer as to when a new coordination study is required. For this reason, we offer the following proposed changes to Requirement R2 (see bold face changes):

R2. Each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1, **for an aggregate Facility nameplate capability change of 10 % or more**, prior to implementation of systems, equipment, or settings changes **when such changes have a direct impact on the existing** coordination **as** described in Requirement R1. Associated coordination documentation shall be updated within 90 calendar days after the return to in-service date. These possible systems, equipment, or settings changes include the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez

Answer	No
Document Name	

Comment

SRP prefers IBR's have their own set of standards versus incorporating them into current standards.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

Black Hills Corporation supports the NAGF comments.

Likes 0	
Dislikes 0	

Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum (NSRF) comments	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation does not agree with the expanded scope as it will essentially double the work as the Generator Owner will now need to perform a coordination study prior to syncing to grid and then perform a second coordination study following commissioning testing (following tuning). It is impractical to install or reprogram a relay or AVR, identify the as-left settings, then wait a month or two before restarting the unit to have a contractor re-perform or update the PRC-019 study. PRC-019 should provide latitude for the coordination study based on analysis of intended settings, then allow for issuance of a revised report within 90 days of implementation if there are any deviations between intended and as-left settings identified. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
NPPD supports comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
The inclusion of "IBR unit control system firmware or settings changes" and "IBR generating Facility power plant controller firmware or settings changes" will possibly require information only known by the manufacturer. NIPSCO recommends 180 calendar days instead of 90 calendar days be allowed to obtain this information.	

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comemnts of the Edison Electric Institute (EEI) to questions #10.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

MPC supports MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

The associated coordination documentation should be updated prior to a return to service, not within 90 days after a return to service

Likes 0	
Dislikes 0	

Response	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
• Firmware changes should not be required a coordination study to be performed.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	
• Section B, R2: A full coordination study should not be required for IBR or PPC firmware changes unless there is a specific addition of new limiter settings. • The 90-day grace period or its equivalent should be restored. At a minimum, PRC-019 needs to retain a grace period to triage an unexpected field change. As noted in the SAR, "The original SDT has confirmed that the 90-day time frame was for scenarios in which an entity discovered a miscoordination." • There are fundamental differences in dispersed power producing resources as identified through inclusion I4 of the BES definition and NERC Standards need to account for these differences. • Unexpected field changes can and will occur at dispersed power producing resources as identified through inclusion I4 of the BES definition because of the quantity of small individual generators at these types of generation facilities. • Manufacturers can and do at times make mistakes and ship equipment with different software, firmware settings, controls or equipment different than was specified.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Similar to R1, clarify that R2 is applicable for Generator Owners or Transmission Owners that own an applicable facility. We suggest the underlined	

statement be added: “Each Generator Owner and Transmission Owner ***with applicable facilities*** shall perform the coordination described in Requirement R1…”.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	

Comment

Enel supports comments made by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	

Comment

AZPS recommends that Requirement 2 (bullet 5) only apply to IBR unit control system firmware or settings changes that effect the protection of the unit. AZPS also recommends that the language “Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in R1, each Generator and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1.”

AZPS also supports the following comments submitted by EEI on behalf of its members:

EEI does not support the current open ended language (i.e., “but are not limited to those listed below”) used in Requirement R2. We also have concerns that the language in Requirement R2 could be clearer as to when a new coordination study is required. For this reason, we offer the following proposed changes to Requirement R2 (see bold face changes):

R2. Each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1, **for an aggregate Facility nameplate capability change of 10 % or more**, prior to implementation of systems, equipment, or settings changes **when such changes have a direct impact on the existing that will affect the** coordination **as** described in Requirement R1. Associated coordination documentation shall be updated within 90 calendar days after the return to in-service date. These possible systems, equipment, or settings changes include, **but are not limited to,** the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

Likes 0	

Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF notes that a full coordination study should not be required for IBR or PPC firmware changes unless there is a specific addition of new limiter and/or protection settings/functionality.	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The MRO NSRF provides the following comments related to Requirement R2.:

- The 90-day grace period or its equivalent should be restored. At a minimum, PRC-019 needs to retain a grace period to triage an unexpected field change. As noted in the SAR, “The original SDT has confirmed that the 90-day time frame was for scenarios in which an entity discovered a miscoordination.”
- There are fundamental differences in dispersed power producing resources as identified through inclusion I4 of the BES definition and NERC Standards need to account for these differences.
- Unexpected field changes can and will occur at dispersed power producing resources as identified through inclusion I4 of the BES definition because of the quantity of small individual generators at these types of generation facilities.
- }Manufacturer can and do at times make mistakes and ship equipment with different software, firmware settings, controls or equipment different than was specified.

- NERC can and does require extensive inverter parameter changes to solve newly identified events such as the Odessa events, the new NERC Alert (R-2023-03-14) on Essential Actions.

- Zero defect for large populations is not effective or efficient approach.
- Consider each wind / solar farm may have 100 – 200 individual inverters with 500 parameters per inverter, or 50,000 to 100,000 chances for an

error every day.
- Alternately, NERC could begin creating non-zero defect standards / requirements with the ability to self-log / self-report, self-correct and keep regulatory records for small issues (1%, 2%, or 5). Something like a six-sigma versus zero defect.

Likes 1	Kelley Tim On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Fou
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC Generator Working Group a new study shouldn't have to be resubmitted for firmware updates that don't affect controls. Suggest specifying that in the requirement.	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	

See comment above. WECC believes footnote 3 should be eliminated, or changed to "Any as-left protection system setting may be utilized in protection and control coordination studies", thus removing the implication that a coordination study is required as part of PRC-019.

Likes 0	
Dislikes 0	

Response
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment
FE supports EEI comments with the additional edits in bold for Requirement R2: A full coordination study should not be required for IBR or PPC firmware changes unless there is a specific addition of new limiter settings **or changes to reactions of the existing limiters**.

Likes 0	
Dislikes 0	

Response
Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment
Talen supports the comments of the NAGF.

Likes 0	
Dislikes 0	

Response
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group supports the MRO NSRF and the NAGF comments.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

Driven by the same reasoning and concerns as expressed in Response #9, the inclusion of “IBR unit control system firmware or settings changes” and “Power plant controller firmware or settings changes” may prove problematic. The challenges illustrated in our response to Question #9 support our position that 90 days is an extremely aggressive timeframe for the Generator Owner or Transmission Owner to obtain information and insight that might possibly be known only by the manufacturer, and potentially including proprietary information. Rather than 90 days, AEP recommends that a) 180 days be allowed to document a plan to obtain this additional information from the manufacturer and b) an additional 90 days to perform the coordination per R1. If the SDT is unwilling to make such a change, perhaps it would consider allowing for a longer provision period, as agreed upon by the requestor and data provider.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC

Answer	Yes
Document Name	

Comment

NO (the voting button could not be changed). SMUD and BANC agree with the comments provided by MRO NSRF that the 90-day grace period or its equivalent should be restored.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	
We support RSC comments	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
AEPC signed on to ACES comments below: How will entities verify that changes will NOT affect the coordination? While the intent of this language identified in the April 2023 PRC-019-3 Technical Rationale document is laudable, the current verbiage seems to require that the GO/TO "prove the negative". We suggest modifying the language in R2 as follows: "Each Generator Owner and Transmission Owner shall review the coordination described in Requirement R1 prior to implementation of systems, equipment, or settings changes that could affect the coordination described in Requirement R1. If changes are identified that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1 prior to implementation." While this proposed modification may seem minor on the surface, we believe that it allows greater flexibility for the entity when reviewing changes that may impact coordination while also meeting the stated intent of the SDT. In other words, we believe that the current verbiage necessitates that the entity attempt to "prove the negative" by generating evidence "that a particular change made to systems, equipment, or settings will not affect the coordination". Whereas we believe that the verbiage we proposed will only require evidence that the entity perform a coordination study whenever an impact to coordination is identified.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	Yes

Document Name	
Comment	
PNM supports the changes proposed in PRC-019-3, Requirement R2.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
The standard introduces the term "Firmware changes", but it only associates the term with IBR control systems. In the bullet corresponding to protective functions only settings and component changes are mentioned. Should protective functions include firmware changes? since most of the microprocessor relays have updatable firmware.	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz County PUD No. 1, 5, 6/7/2023	
Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	Yes

Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	

Manitoba Hydro agrees that it is now written that clears up the language that a process needs to be in place that a protection and control coordination occurs prior the unit being placed in service and is documented.

Manitoba Hydro agrees with the timelines given that during commissioning, in an ideal world, the as left settings from the exciter would verified with the compliance documentation before the unit is placed in service, however since this is very difficult to do, the 90 day window is there to verify the as left settings with the compliance documentation.

Manitoba Hydro agrees that if you do a firmware upgrade for an IBR, all that is required is that you check the as left settings with the coordination, ensure they are the same and document the dates of the firmware change and that it didn't change the settings.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 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	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC - no Comment From response received from Standard Owners or SMEs	
Likes 0	
Dislikes 0	
Response	

11. Do you agree the language proposed in PRC-019-3 Attachment 1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

Examples diagrams have been removed from PRC-019, and are no longer found in either the standard or its associate Technical Rationale document. We believe this information is helpful and recommend that it be retained within the Technical Rationale document, and that it also be updated to reflect the proposed revisions to the standard (including for IBRs).

The SDT stated in their previous Consideration of Comments document that they had removed all reference to "protection functions", however one reference remains in Attachment 1 which states "NOTE: This standard does not require the installation or activation of any of the limiter or protection functions for synchronous generation or IBR."

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group supports the MRO NSRF and the NAGF comments.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

Voltage dependent protection functions needs to be clarified what is the safe voltage limit. Currently voltage based functions are coordinated at 1 p.u.

and this coordination will hold little value when an event such a loss of field occurs and the voltage will drop.

Some generators/synchronous condensers do not have equipment capability information provided such as volts per hertz capability due to the age of the equipment. Further wording in the standard needs to be clarified what to do if this information if not provided.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

Talen supports the comments of the NAGF.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy supports EEI's comments which state:

Section A: EEI does not agree that the plant's "Distributed control system (DCS) should be included in a protection coordination because protection engineers have no control or input into those systems rendering any effort to provide reliable coordination with voltage/VAR limit settings in those systems nearly impossible.

Section B: See first note above. Items such as "Reactive compensating devices voltage control functions" and "IBR unit momentary cessation protection function" should be removed from this list. Momentary cessation is not a protection function and has been liberally renamed; this is a loss-of-control function.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC Generator Working Group: In section B Mixes control functions (like momentary cessation) and protection functions. Also, "associated control/protection functions" terms are to vague/broad	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The MRO NSRF does not agree with the use of the undefined term Inverter-based resource (IBR), please see response to question 9. Further, "Reactive compensating devices voltage control functions" and "IBR unit momentary cessation protection function" are neither limiters or protection functions and need to be removed, perhaps the SDT should consider current (i). The term "control function" is used throughout Attachment 1, Section B and should be removed or changed to "limiters". The term "protective function" should be change to "Protection System setting". Utilizing a defined term clearly articulates what needs to be coordinated. Further, Attachment 1 uses "include but are not limited to" throughout. The MRO NSRF disagrees with "include but are not limited to" language as it is	

open ended and subject to interpretation by both responsible entities and enforcement authorities. The MRO NSRF suggests removing the language in its entirety in Attachment 1.

Likes 1	Kelley Tim On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Fou
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The NAGF recommends that the language for the proposed PRC-019-3 Attachment 1 be revised to address the following:

a. Section A - recommend removal of “Distributed control system (DCS) voltage/VAR limit settings” bullet. These DCS limits are often set completely independent of protection engineers’ input and are at the discretion of controls engineers and/or plant operations personnel.

b. Section B - See response to Question 9 above. Items such as “Reactive compensating devices voltage control functions” and “IBR unit momentary cessation protection function” should be removed from this list. Momentary cessation is not a protection function; rather it is a loss-of-control function.

The proposed revision adds “and associated control function” to the end of each bulleted example. A NERC standard should not list such vague examples or requirements, such that GOs/TOs are susceptible to falling out of compliance on a subjective basis. Furthermore, the control function does not even make sense in all listed examples. For example, what is an associated control function for Transformer overvoltage protection function?

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS supports the following comments submitted by EEI on behalf of its members:

EEI does not support the open ended language used in both Sections A and B of Attachment 1. Specifically, the ending phrase of both Section A and B state “include but are not limited to” does not conform to a Results Based Reliability Standard and needs to be removed. Such language places responsible entities compliance subject to the individual interpretation of an auditor rather than the clear language that should be included in a NERC Reliability Standard.

We are concerned with the inclusion of bullet 8 which includes Distributed Control Systems (DCS). Generally, protection engineers have no insights into the programing of these systems and these setting are subject to change without their knowledge. For this reason, we seek more clarity regarding the need for the inclusion of systems, noting that given the above limitations any effort to and protection coordination studies noting provide reliable coordination with voltage/VAR limit settings in those systems is unlikely to be successful.

The items such as “Reactive compensating devices voltage control functions” and “IBR unit momentary cessation protection function” should be removed from the Section B list. Momentary cessation is not a protection function and has been liberally renamed within IBR systems moreover this is a loss-of-control function, not a protection function.

We seeks clarity on the addition of “and associated control function” to the end of each bulleted item under Section B. As mentioned earlier in our comments, control functions are undefined and add substantial ambiguity to this Reliability Standard and should be removed unless defined. Furthermore, the addition of “and control function” to every item is unclear and should be explained. For example, what is an associated control function for Transformer overvoltage protection function?

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	

Comment

Enel supports comments made by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

- Attachment 1, Section A: Recommend removal of “Distributed control system (DCS) voltage/VAR limit settings.” These DCS limits are often set completely independent of protection engineers’ input and are at the discretion of controls engineers and/or plant operations personnel.
- Attachment 1, Section B: See first note above. Items such as “Reactive compensating devices voltage control functions” and “IBR unit momentary cessation protection function” should be removed from this list. Momentary cessation is not a protection function and has been liberally renamed; this is a loss-of-control function.
- Attachment 1, Section B: This revision adds “and associated control function” to the end of each bulleted example. A NERC standard should not list such vague examples or requirements, such that GOs/TOs are susceptible to falling out of compliance on a subjective basis. Furthermore, the control function does not even make sense in all listed examples. For example, what is an associated control function for

Transformer overvoltage protection function?	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Regarding Attachment 1, Section 1, it is unclear if alarming related to a DCS voltage/VAR limit setting would be considered a “protection function”. For example, if an operator receives an alarm that is sourced from the DCS, and this alarm is not coordinated per PRC-019, and the alarm may lead the operator to act, would the set point of this alarm need to be coordinated per PRC-019? If an alarm is considered a protection function, is there a nominal voltage level, for example generator bus voltage or auxiliary/station service bus voltage, that would fall outside the scope of the protection function? MPC also supports MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No

Document Name	
Comment	

Eversource supports the comments submitted by EEI.

Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster

Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comemnts of the Edison Electric Institute (EEI) to questions #11.

Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	
Comment	

The example diagrams that were removed should be returned along with the addition of new examples specifically for IBRs.

Likes 0	
Dislikes 0	
Response	

Jamison Cawley - Nebraska Public Power District - 1

Answer	No
Document Name	
Comment	

NPPD supports comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation aligns comments with NAGF. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum (NSRF) comments	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	

Black Hills Corporation supports the NAGF comments.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	No
Document Name	

Comment

Black Hills Corporation supports the NAGF comments.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

Black Hills Corporation supports the NAGF comments.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez

Answer	No
Document Name	

Comment

SRP prefers IBR’s have their own set of standards versus incorporating them into current standards.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI does not support the open ended language used in both Sections A and B of Attachment 1. Specifically, the ending phrase of both Section A and B state “include but are not limited to” does not conform to a Results Based Reliability Standard and needs to be removed. Such language places responsible entities compliance subject to the individual interpretation of an auditor rather than the clear language that should be included in a NERC Reliability Standard.

We do not support the inclusion of bullet 8 under Section A of Attachment 1, which includes Distributed Control Systems (DCS). Generally, protection engineers have no insights into the programing of these systems and those setting are subject to change without their knowledge. For this reason, we seek more clarity regarding the need for the inclusion of these systems, noting that given the above limitations any effort to include these settings into protection coordination studies is unlikely to yield any long term beneficial results.

Section B Bulleted Items: Items such as “Reactive compensating devices voltage control functions” and “IBR unit momentary cessation protection function” should be removed from the Section B list. Momentary cessation is not a protection function and has been liberally renamed within IBR systems moreover this is a loss-of-control function, not a protection function.

We seeks clarity on the addition of “and associated control function” to the end of each bulleted item under Section B. As mentioned earlier in our comments, control functions are undefined and add substantial ambiguity to this Reliability Standard and should be removed unless defined. Furthermore, the addition of “and control function” to every item is unclear and should be explained. For example, what is an associated control function for Transformer overvoltage protection function?

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation agrees with comments made by NAGF.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	

Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI is supportive of the comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
The list of IBR functions is extensive. Refer to Question 9 response regarding more guidance is needed on how coordination between all of these elements is shown. Additionally, legacy plants may no longer have inverter OEMs in business for consultation. Therefore, collecting details that were not standard to give to the customer when the plant was commissioned, such as momentary cessation, is impossible. The SDT should consider legacy units where information may not be available.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	

Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz County PUD No. 1, 5, 6/7/2023	
Likes 0	
Dislikes 0	
Response	

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE supports comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports the changes proposed in PRC-019-3, Attachment 1	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	
We support RSC comments	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	

Answer	Yes
Document Name	
Comment	
Ameren believes that control functions that limit voltage/MVAR should not be changed without being studied for coordination.	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC

Answer	Yes
Document Name	
Comment	
NO (the voting button could not be changed). Attachment 1 uses “include but are not limited to” throughout. SMUD and BANC agree with the comments provided by the MRO NSRF, in that the “include but are not limited to” language is open ended and subject to interpretation by both responsible entities and enforcement authorities. This language should be removed in its entirety from Attachment 1.	
Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	Yes
Document Name	
Comment	
PG&E agrees with the proposed language in Attachment 1.	
Likes 0	
Dislikes 0	
Response	

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

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	

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC - no Comment From response received from Standard Owners or SMEs	
Likes 0	
Dislikes 0	
Response	

12. The SDT believes the language of PRC-019-3 addresses the issues outlined in the two SARs in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

As the desired coordination is unclear, it is difficult to determine what the cost will be.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	

Comment

AECI is supportive of the comments provided by the NAGF.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

As stated above, Constellation does not agree with the expanded scope as it will essentially double the work as the Generator Owner will now need to perform a coordination study prior to syncing to grid and then perform a second coordination study following commissioning testing (following tuning). External vendors are routinely hired to perform the coordination studies and therefore this proposed change significantly increases the cost to the Generator Owner.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez

Answer	No
Document Name	

Comment

SRP prefers IBR's have their own set of standards versus incorporating them into current standards.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer

Answer	No
Document Name	

Comment

Minnesota Power supports MRO's NERC Standards Review Forum (NSRF) comments

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

As stated above, Constellation does not agree with the expanded scope as it will essentially double the work as the Generator Owner will now need to perform a coordination study prior to syncing to grid and then perform a second coordination study following commissioning testing (following tuning). External vendors are routinely hired to perform the coordination studies and therefore this proposed change significantly increases the cost to the Generator Owner.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1

Answer	No
Document Name	

Comment

NPPD supports comments submitted by MRO NSRF.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

MPC supports MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	

Response

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

- GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.

Likes 0	

Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

See comments and suggested improvement items noted in Southern Company responses to the previous questions.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	

Comment

Enel supports comments made by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.

Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The MRO NSRF believes that the proposed language, as noted in our responses to questions nine, 10 & 11, is not clearly articulating what is and is not in scope. The intention of this standard is to ensure Protection System setting that respond to electrical quantities and limiters that affect these electrical quantities are coordinated to ensure no unnecessary Protection System activations occur; it seems that the scope has expanded well beyond the intention.	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
NERC does not provide guidance for IBR OEM to comply with regulatory standards.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Until the Drafting Team provides clarification and guidance, FirstEnergy cannot determine the scope of this standard in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Talen supports the comments of the NAGF.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the MRO NSRF and the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz County PUD No. 1, 5, 6/7/2023	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	

These changes will increase the workload, processes and evidence collected.

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
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	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
At this time PG&E has not been able to complete a cost analysis on the impact of the modifications.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC - no Comment From response received from Standard Owners or SMEs	

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	
Document Name	

Comment

Black Hills Corporation will not provide comment on cost-effectiveness.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	
Document Name	

Comment

Black Hills Corporation will not provide comment for cost-effectiveness.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	
Document Name	

Comment

Black Hills Corporation will not provide comment on cost-effectiveness.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	

13. The SDT proposes a 1-year implementation plan for PRC-019-3 Requirement R2, with an additional 1 years (2 years total) for compliance with Requirements R1. The reoccurring 5-year periodicity of Requirement R1 has been removed. Would these proposed timeframes give enough time to put into place process, procedures or technology to meet the proposed language? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period.

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Reclamation recommends a 2-year implementation plan for both requirements R1 and R2.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA supports comments submitted by the US Bureau of Reclamation that a 2-year Implementation Plan be applied to PRC-019-3 for both R1 and R2.	
Likes 0	
Dislikes 0	

Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Until the Drafting Team provides clarification and guidance, FirstEnergy cannot determine the implementation scope of this standard.	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The MRO NSRF believes that the implementation plan needs to account for the original 5-year periodicity and allow existing entities to perform the PRC-019-3 study in accordance with that date (original 5-year periodicity).	
Likes 0	
Dislikes 0	

Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Recommend a 1-year implementation plan and an additional 2 years (3 years total) for compliance with R1. This will allow a better opportunity to perform any physical modifications required during scheduled outages.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Enel supports comments made by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company believes that the implementation plan needs to account for the original 5-year periodicity and allow existing entities to perform the PRC-019-3 study in accordance with that date (original 5-year periodicity).	
Likes 0	

Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
• Entergy do not agree with the 1-year implementation plan for R1. Should DCS settings require review or updating in the existing reports generated for PRC-019-2, the 1- year Implementation plan does not provide enough time for a vendor to generate the test report, complete Site reviews of the report, address/incorporate comments, generate the Engineering change to create and complete the associated Engineering Report. Recommend a 2- year implementation requirement for R1	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
NPPD supports comments submitted by MRO NSRF.	
Likes 0	
Dislikes 0	

Response	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Hillary Creurer	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum (NSRF) comments	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP prefers IBR's have their own set of standards versus incorporating them into current standards.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren will wait to comment on the implementation plan until the changes discussed in Question 9 are addressed by the drafting team.	
Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	

Much like how the initial effective version of the standard had a staged implementation plan with increasing percentages of each entity's Facilities needing to reach compliance, this implementation plan needs the same staging. This is especially the case for IBRs, as their burden for demonstration of compliance is increased and the guidance for reaching compliance is still lacking.

Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	
Response	

Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
Deanna Carlson, Cowlitz County PUD No. 1, 5, 6/7/2023	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF supports the proposed PRC-019-3 implementation plan.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes

Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports the implementation plan timeline as proposed.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation agrees with the 6 year periodicity from the last protection study performed in order to align with historical work completed under PRC-019-2 Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes

Document Name	
Comment	

Constellation agrees with the 6 year periodicity from the last protection study performed in order to align with historical work completed under PRC-019-2.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	

EEI supports the implementation plan as proposed.

ADDITIONAL COMMENTS FOR SDT CONSIDERATION

Given there is no place within the provided set of questions to provide any additional concerns, we are including our additional concerns below:

Upon review of the Applicability Section of PRC-019-3, it appears that, unlike MOD-025-3, which is aligned with the BES Definition; further alignment is still needed. As an example, both 4.2.4 (Inverter-based resources generating plant/Facilities) does not include "as identified through Inclusion I4 of the BES definition) and 4.2.3 (synchronous condensers) similarly does not references to Inclusion I5. This change should be made prior to the next draft of MOD-025-3.

Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	Yes
Document Name	
Comment	

AECI is supportive of the comments provided by the NAGF.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	Yes
Document Name	

Comment

PG&E supports the Implementation Plan as proposed.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Stephen Whaite - Stephen Whaite On Behalf of: Lindsey Mannion, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
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	

Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; - James Mearns	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
No Comment.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	

Comment	
ITC - no Comment From response received from Standard Owners or SMEs	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
According to the Initial Performance of Periodic Requirements within the implementation plan, existing entities shall comply within 66 calendar months from last performance for next test under V3. Additionally, if the timeframe for existing units to perform testing falls between the effective date of the standard and the compliance date, the applicable entity shall comply by the Compliance date. However, this is confusing as existing resources that have been tested close to the new effective date under Version 2 may exceed the 2 year compliance date for the next iteration of testing allowed (66 months). This is not clear. It would be better to start the compliance date unilaterally for existing and new applicable units under all requirements to avoid confusion. In this way, test results performed under the new requirements would also be properly reviewed by the Transmission Planner under R3 and R4.	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	
Additinal Comment: Please consider ensuring that the Facilities section is aligned with the BES definition.	
Likes 0	
Dislikes 0	
Response	