Comment Report

Project Name:	2020-06 Verifications of Models and Data for Generators | Draft 1
Comment Period Start Date:	5/24/2022
Comment Period End Date:	7/6/2022
Associated Ballots:	2020-06 Verifications of Models and Data for Generators Implementation Plan IN 1 OT 2020-06 Verifications of Models and Data for Generators MOD-026-2 IN 1 ST

There were 79 sets of responses, including comments from approximately 180 different people from approximately 110 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The standard drafting team (SDT) proposes combining MOD-026-1 and MOD-027-1 into a single standard, MOD-026-2, due to the efficiency of having one standard with common process and requirement language. Do you agree with this approach? 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-026-2 Requirement R1? 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-026-2 Requirements R2 and R3? 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-026-2 Requirements R4 and R5? 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-026-2 Requirement R6? 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-026-2 Requirements R7, R8, and R9? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

7. The SDT believes the language of MOD-026-2 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 Requirements R1, R7, R8, and R9, with an additional 2 years for compliance with Requirements R2-R6 for newly applicable Facilities. For existing Facilities, the Implementation Plan proposes the ten year reoccurring periodicity is maintained from the date of previous model verification. 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. Provide any additional comments on the standard and technical rationale document for the SDT to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
Santee Cooper	Chris Wagner	1		Santee Cooper	Paul Camilletti	Santee Cooper	1,3,5,6	SERC
					Rene' Free	Santee Cooper	1,3,5,6	SERC
					Anthony Noisette	Santee Cooper	1,3,5,6	SERC
Portland General Electric Co.	Daniel Mason	6		Portland General Electric Co.	Brooke Jockin	Portland General Electric Co.	1	WECC
					Adam Menendez	Portland General Electric Co.	3	WECC
					Ryan Olson	Portland General Electric Co.	5	WECC
					Daniel Mason	Portland General Electric Co	6	WECC
James Mearns	James Mearns			NCPA HQ	Jeremy Lawson	Northern California Power Agency	5	WECC
					Marty Hostler	Northern California Power Agency	4	WECC

					Dennis Sismaet	Northern California Power Agency	6	WECC
					Michael Whitney	Northern California Power Agency	3	WECC
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
LaKenya VanNorman	LaKenya VanNorman		SERC	Florida Municipal Power Agency (FMPA)	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Carl Turner	Florida Municipal Power Agency	3	SERC

					Jade Bulitta	Florida Municipal Power Agency	6	SERC
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
					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Public Utility District No. 1 of Chelan County	Meaghan Connell	5		PUD No. 1 of Chelan County	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
					Meaghan Connell	Public Utility District No. 1 Chelan County	5	WECC
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
Southern Company - Southern Company	Pamela Frazier	1,3,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern Company	1	SERC

Services, Inc.						Services, Inc.		
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					James Howell	Southern Company - Southern Company Generation	5	SERC
Eversource Energy	Quintin Lee	1		Eversource Group	Quintin Lee	Eversource Energy	1	NPCC
					Christopher McKinnon	Eversource Energy	3	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Harish Vijay Kumar	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International	5	NPCC

	Inc.		
Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	5	NPCC
Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
Nurul Abser	NB Power Corporation	1	NPCC
Randy MacDonald	NB Power Corporation	2	NPCC
Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
Vijay Puran	NYSPS	6	NPCC
ALAN ADAMSON	New York State Reliability Council	10	NPCC
Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
Brian Robinson	Utility Services	5	NPCC

					Quintin Lee	Eversource Energy	1	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Sunny Raheem	Southwest Power Pool Inc	2	MRO
					Doug Bowman	Southwest Power Pool Inc	2	MRO
					Matt Harward	Southwest Power Pool Inc	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC

Tim Kelley	Tim Kelley		WECC	LPPC	Holly Chaney	Snohomish County PUD No. 1	3	WECC
					Joe McClung	JEA	1	SERC
					Nicole Looney	Sacramento Municipal Utility District	3	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					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	1	SERC

						Cooperative		
					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. The standard drafting team (SDT) proposes combining MOD-026-1 and MOD-027-1 into a single standard, MOD-026-2, due to the efficiency of having one standard with common process and requirement language. Do you agree with this approach? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Although process and requirement language have basic commonalities across the two standards, MOD26-1 covers generator excitation system testing and modeling and MOD27-1 covers Turbine speed governor control system testing and modeling. These systems are unique to each system's function, testing is wholely unique to each system, and models are wholely unique to each system. Testing may be staged serparately, might be performed by different testing entities and model verification is evaluated for compliance for each on a serparte basis. There is practical clarity retaining separate MOD26 and MOD27 standards as is.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
This approach works well for inverter-based resources but not synchronous machines. If different systems are modified separately, the validation process becomes convoluted. This approach will also add a significant cost to GOs that already have detailed work orders, program documents, and procedures in place to assist in compliance with the existing standards. Previous NERC audits drove GOs to have these documents in place. Options: 1. Modify R7 to specify that R2, R3, R4, R5, and R6 can be complied with and submitted separately to ensure there is no confusion between GOs and TPs. This action will also assist with the conduct of audits. 2. Create separate standard for inverter based resources.	
Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No

Document Name	
Comment	

Xcel Energy generally supports the comments of EEI. Below are Xcel Energy comments that indicate additional or differing concerns.

Xcel Energy disagrees with including excitation modeling (R2) and governor modeling (R3) within the same standard. A modification to "governor" shall not require a revision to the excitation model, and vice-versa. MOD-026-2 submittal shall allow for only submitting modeling for applicable equipment that is modified. Although they have similar reporting requirements, there are no commonalities between an excitation system and a turbine-governor system in a synchronous generating facility. Even further, it will be more confusing to include both synchronous, non-synchronous, and IBR generating facilities in the same standard. It makes more sense to have non-synchronous and IBR resources covered under a separate standard since those resources are not at all similar to synchronous generation.

Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Pam Syrjala, Salt River Project, 5, 3, 1, 6; Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez

Answer	No
Document Name	
Comment	

It would seem more logical to provide a new MOD standard rather than version 2 of MOD-026-1. We believe that it may be best to retire both standards, as to minimize any confusion of what was, continue to be, and the new requirements. Better off creating a whole new standard.

Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO

Answer	No
Document Name	
Comment	

While the MRO NSRF appreciates the regulatory efficiency of combining MOD-026 and MOD-027, it has concerns that combining MOD-026 and MOD-027 could in effect make Primary Frequency Response (PFR) retroactive by stating models must be developed in R3. The MRO NSRF suggests the Standards Drafting Team (SDT) add the words “in accordance with FERC Order 842” to R3 to clarify and differentiate between generators that are and are not required to have PFR. The MRO notes that only generators with signed interconnection contracts after May 15, 2018 are required to have PFR.

Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry

Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican supports MRO NSRF and EEI 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	
The NAGF supports the consolidation of MOD-026 and MOD-027 into one standard to create efficiency and clarity; However, as the draft standard is currently written, the NAGF does not believe the objectives of clarity and efficiency have been met and for this reason the NAGF does not support the consolidation of these two standards at this time. In addition, the NAGF supports the EEI comments on this question.	
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; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	No
Document Name	
Comment	
Significant duplication of MOD-032-1 model validation requirements and processes. MOD-026 if consolidated with MOD-027 should be focused on specific model and site configuration verification processes.	
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 combining MOD-026 and MOD-027 could in effect make Primary Frequency Response (PFR) retroactive by stating models must be developed in R3. We, too, suggest the SDT add the words “in accordance with FERC Order 842” to R3 to clarify and differentiate between generators that are and are not required to have PFR included in the control functions available. - notes that only generators with signed interconnection contracts after May 15, 2018 are required to have PFR included in the control functions available.	
Likes 0	
Dislikes 0	
Response	
James Howell - Southern Company - Southern Company Generation - 5	
Answer	No
Document Name	
Comment	

See Southern Company Comments

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

While the two standards are similar in that they require verification of modeling data used for dynamic simulations, the equipment they impact are totally different, i.e. for synchronous generators - generator/AVR/Exciter for MOD-026 and turbine/turbine control system for MOD-027. As such, it makes more sense to keep them separate so that there is no confusion on which requirements/exceptions apply to each. How does having one standard vs. two standards help, particularly if it leads to confusion on the requirements? By combining the standards, Attachment 1 becomes even more convoluted than it is in the current MOD-026-1 / MOD-027-1. If the standards are combined, for units without frequency control systems necessary (MOD-027-1 not applicable), clearly state in the standard that these are exempt for the requirement.

Likes 0	
Dislikes 0	

Response

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County

Answer	No
Document Name	

Comment

Combining governor modeling and excitation modeling into the same standard is less efficient in practice than keeping MOD-026 and MOD-027 separate from both an operational and administrative perspective.

Operational Considerations:

For existing facilities, governor systems and excitation systems are often changed, replaced, or tested independently. Therefore, throughout the implementation of MOD-026-1 and MOD-027-1, governor system modeling and excitation system modeling has been tracked and managed very independently. From an operational perspective, there is no efficiency gain from combining MOD-026-1 and MOD-027-1.

Administrative Considerations:

Presently, the entire industry has established compliance and internal controls programs to track the implementation of MOD-026-1 and MOD-027-1 independently. Enterprise work order management systems, work practice guidelines, and compliance tracking tools have been established to address excitation modeling per MOD-026-1 and governor modeling per MOD-027-1. Combining MOD-027-1 and MOD-026-1 will introduce an immense administrative burden resulting from the need to restructure the compliance programs that have already been established.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	Yes
Document Name	

Comment

EEI supports the concept of consolidating the requirements of MOD-026-1 with MOD-027-1, however, the language used within the Applicability section of proposed MOD-026-2 raises questions regarding what constitutes an individual generating unit under Inclusion I2 and what constitutes a dispersed power producing resource under Inclusion I4. As more hybrid resources are installed (i.e., synchronous generators with battery storage) and collocated at existing synchronous plant sites, it is unclear how these resources are to be modeled and what modeling requirements need to be imposed.

For this reason, the SDT should more clearly define how hybrid and collocated synchronous generator and IBR resources are to be model.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	Yes
Document Name	

Comment

No Comments

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

FirstEnergy supports EEI's comments :

EEI supports the concept of consolidating the requirements of MOD-026-1 with MOD-027-1, however, the language used within the Applicability section of proposed MOD-026-2 raises questions regarding what constitutes an individual generating unit under Inclusion I2 and what constitutes a dispersed power producing resource under Inclusion I4. As more hybrid resources are installed (i.e., synchronous generators with battery storage) and collocated at existing synchronous plant sites, it is unclear how these resources are to be modeled and what modeling requirements need to be imposed.

For this reason, the SDT should more clearly define how hybrid and collocated synchronous generator and IBR resources are to be model.

Likes 0	
Dislikes 0	

Response

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

Comment

AECI supports EEI's comments :

EEI supports the concept of consolidating the requirements of MOD-026-1 with MOD-027-1, however, the language used within the Applicability section of proposed MOD-026-2 raises questions regarding what constitutes an individual generating unit under Inclusion I2 and what constitutes a dispersed power producing resource under Inclusion I4. As more hybrid resources are installed (i.e., synchronous generators with battery storage) and collocated at existing synchronous plant sites, it is unclear how these resources are to be modeled and what modeling requirements need to be imposed.

For this reason, the SDT should more clearly define how hybrid and collocated synchronous generator and IBR resources are to be model.

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	

Comment

Constellation agrees with this approach, however requests the consideration to allow excitation and governor modeling to be done separately and not in conjunction, as completing modelings together at the next interval cycle would short cycle models completed under the original implementation plan. As models were planned and executed separately throughout the periodic implementation.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	

Comment

Constellation agrees with this approach, however requests the consideration to allow excitation and governor modeling to be done separately and not in conjunction, as completing modelings together at the next interval cycle would short cycle models completed under the original implementation plan. As models were planned and executed separately throughout the periodic implementation.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

ATC sees efficiency and potential benefit in combining the two standards. Having to only reference one complete set of similar requirements could be easier for reference than using two separate standards.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	Yes
Document Name	

Comment	
The concept of consolidating the requirements of MOD-026-1 with MOD-027-1 is supported, however, the language used within the Applicability section of proposed MOD-026-2 raises questions regarding what constitutes an individual generating unit under Inclusion I2 and what constitutes a dispersed power producing resource under Inclusion I4. As more hybrid resources are installed (i.e., synchronous generators with battery storage) and collocated at existing synchronous plant sites, it is unclear how these resources are to be modeled and what modeling requirements need to be imposed. For this reason, the SDT should more clearly define how hybrid and collocated synchronous generator and IBR resources are to be model.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the concept of consolidating the requirements of MOD-026-1 with MOD-027-1, however, the language used within the Applicability section of proposed MOD-026-2 raises questions regarding what constitutes an individual generating unit under Inclusion I2 and what constitutes a dispersed power producing resource under Inclusion I4. As more hybrid resources are installed (i.e., synchronous generators with battery storage) and collocated at existing synchronous plant sites, it is unclear how these resources are to be modeled and what modeling requirements need to be imposed. For this reason, the SDT should more clearly define how hybrid and collocated synchronous generator and IBR resources are to be model.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Derek Brown, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) to question #1.	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP has no objections to the concept of combining MOD-026-1 and MOD-027-1 into a single standard, provided that the resulting obligations themselves are sound.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	Yes
Document Name	
Comment	
Texas RE appreciates the SDT's efforts to make the standard more efficient and more clear. Texas RE agrees with the approach to combine MOD-026 and MOD-027.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	Yes
Document Name	
Comment	
The language in the standard shall make it clear that model verification does not have to occur at the same time for different components.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA supports combining the standards in general, just not as currently proposed. This proposed consolidation greatly exceeds the scope of what is currently within MOD-026-1 and MOD-027-1. BPA does not believe the scope increase is appropriate.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes

Document Name	
Comment	
Currently Black Hills Corporation supports additional information that EEI has stated in their comments. In addition to Transmission Planner, Planning Coordinator needs to be added to the language.	
Likes 0	
Dislikes 0	
Response	
Aric Root - CMS Energy - Consumers Energy Company - 4	
Answer	Yes
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI for Question #1. Submitted on behalf of Exelon, Segments 1 & 3	
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 comments provided by EEI as they relate to clearly defining how hybrid and collocated synchronous generator and IBR resources are modeled.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
Support combining MOD 26 & 27; however, support the comments from EEI	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
However, not as currently drafted. Support BPA's comment.	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 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	

Nazra Gladu - Manitoba Hydro - 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	

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

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

Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Dwanique Spiller, Berkshire Hathaway - NV Energy, 5; - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 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	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
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 Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Buckeye Power, Inc. - 5	

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	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
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	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	

Answer	
Document Name	
Comment	
National Grid supports EEI's comments.	
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	
The ITC Standards Under Development Team has received no response to submit from the Standard Owners	
Likes 0	
Dislikes 0	
Response	

2. Do you agree the language proposed in MOD-026-2 Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Glenn Pressler - CPS Energy - 3	
Answer	No
Document Name	
Comment	
No. CPS Energy supports the comments from LCRA, CenterPoint, and TexasRE.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	No
Document Name	
Comment	

The SRC does not agree with the language proposed in MOD-026-2 Requirement R1 and requests the following:

R1.1 An acceptable list of positive sequence dynamic models should continue to come through the industry. The industry should always pursue minimization of user defined models. Use of user defined models should be limited to no more than three years. Also, having the industry input for unacceptable models list gives TPs the ability to push back on GOs.

R1.2 EMT models tend to be manufacturer specific and guarded by manufacturers from a confidentiality standpoint. Footnote 1 identifies that TPs will provide detailed EMT modeling requirements. TPs are not EMT modeling experts and are not in a position to determine which models or parameters are best for each generator. Equipment manufacturers or an industry technical expert group should establish EMT data requirements. MOD-026-2 should reduce the barriers and increase the ease of obtaining EMT models for applicable functional entities; e.g. Planning Authority.

R1.3 Minimum and consistent model acceptance criteria should come from the industry for an interconnection wide use (uniform over the interconnection wide area – not local to the TP; e.g. PJM should not have different dynamic criteria than ISONE within the Eastern Interconnection). However, each TP can establish tighter region specific criteria as necessary; within acceptable bounds.

R1.3.1 usability -- being too prescriptive with acceptance criteria may be too restrictive for the TP. For example; just because something falls within bounds; adjustment may be necessary if there are interactions.

R1.3.2 Initialization -- when the model is initialized, d-state errors must not appear, which is software driven – the TP does not establish;

R1.3.3 Interoperability -- Interoperability should be software agnostic so that the same model can be used with commercially accepted software and responses are similar among software packages. This seems more appropriate to target to software manufacturers.

R1.4 The SRC supports having submittal requirements available to generation owners.

R1.5 The SRC supports PAs receive verified models.

R1.6 The proposed language appears to remove the 90 day response time requirement. This implies TPs are required to create a method and timeframe for GOs to obtain the information. The SRC requests to keep the 90 day response time requirement, as 90 days acts as a back stop to assure GOs have a date certain to obtain models and provide to their contracted model reviewers.

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 agrees with the comments and recommended modifications provided by EEI.

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 has the following concerns and /or comments:

General:

1. The current language does not limit the number of models that may need to be developed. The cost (time & money) for an entity to produce these models can be significant. If Planning Authorities (PA) and Transmission Planners (TP) are able to continuously request models and / or revisions to models the objective of grid reliability, resiliency and security is jeopardized as resources are pulled toward compliance vs. operations and maintenance. The language should be updated to limit the number of models PA/sTPs can request.

2. The current language does not encourage or mandate consistency in methods, frequency, processes, acceptance criteria, modelling tools etc. This may result in entities in some regions being more tasked than entities in other areas due to the processes of their specific PA / TP. The standard should be updated to include language / details to mitigate the likelihood that the operationalization of this standard may result in very inconsistent experiences for entities in different regions.

3. The NAGF supports EEIs comments

4. The NAGF supports Avista's comments and recommended changes

R1.1

a. Replace "Transmission Planner" with "Transmission Planner and / or Planning Authority"

R1.2

a. The NAGF support's Duke Eenrgy's comments

b. The NAGF supports EEI's comments and recommended edits

R1.4

a. Replace "Transmission Planner" with "Transmission Planner and / or Planning Authority"

R1.5

a. The NAGF supports Avista's comments

b. Replace "Transmission Planner" with "Transmission Planner and / or Planning Authority"

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5

Answer	No
Document Name	

Comment

City of Austin dba Austin Energy requests the SDT provide clarification (perhaps in the form of footnotes) as follows:

- Please describe **parameterization checks** in the context of R1.3.1.
- Please clarify the meaning of **interoperability** in the context of R1.3.2.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	

Comment	

1. Requirement R1 uses inconsistent possessive form of Transmission Planner and the representative pronoun.

The main body of Requirement R1 should be revised to:

Each Transmission Planner and its Planning Authority shall jointly develop dynamic model requirements and processes. The dynamic model requirements and processes shall be made available to the Generator Owner and Transmission Owner by the its Transmission Planner, and include at a minimum the following:

The Requirement R1, Part 1.3 should be revised to:

Acceptance criteria used by the its Transmission Planner to determine disposition in Requirement R8 including at a minimum the following:

The Requirement R1, Part 1.4 should be revised to:

Process for Generator Owner or Transmission Owner to provide verified models to the its Transmission Planner;

2. Requirement R1, Part 1.6 perpetuates an inappropriate reference from MOD-026-1 and MOD-027-1 Requirement R1 (bullet 3) that Transmission Planners are obligated to maintain a database of Generator Owner or Transmission Owner models. This is inconsistent with MOD-032-1 for jointly developed modeling data requirements and reporting procedures of the Transmission Planner and Planning Coordinator, as well as the requirement for Generator Owner or Transmission Owner to submit modeling data to its Transmission Planner and Planning Coordinator. Additionally, the proposed Part 1.6 omits the key reference to current (in-use) models intended to refer to those used for study. The Requirement R1, Part 1.4 should be revised to:

Process for Generator Owner or Transmission Owner to obtain the model(s) modeling representation reflected in its Transmission Planner and Planning Authority current (in-use) models contained in the Transmission Planner's database for an existing Facility owned by the Generator Owner or Transmission Owner.

[*ALTERNATIVE FOR BREVITY*] Process for Generator Owner or Transmission Owner to obtain the modeling representation of the existing Facility it owns from its Transmission Planner and Planning Authority current (in-use) models.

3. Footnote 1 omits Planning Authority and is not consistent with the intent of the proposed Requirement R1. Footnote 1 should be revised to:

1 - Detailed EMT modeling requirements are developed by the Transmission Planner and its Planning Authority to ensure consistent EMT models are provided based on the types of studies being performed and the specific EMT simulation tools being used.

Likes 0	
Dislikes 0	
Response	

Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	No
Document Name	
Comment	

Requirement R1 instructs the TP to maintain a requirement document that states the accepted models and the level of detail needed. This requirement

is largely covered by MOD-032, R1 and is therefore partially redundant.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	
MOD-026-2 R1 states that the Transmission Planner and Planning Authority jointly develop requirements and processes, but only identifies Transmission Planner in the rest of the standard. In some regions the Planning Authority maintains dynamic models, therefore LCRA TSC suggests the SDT adopt language similar to TPL-007-2 R1 stating the Planning Authority, in conjunction with its Transmission Planner(s) identify individual and joint responsibilities of the Planning Authority and Transmission Planner(s) in the Planning Authority's planning area. This change would lead to removing Transmission Planner in the requirements and replacing that with "responsible entity" throughout the standard. LCRA TSC also suggests providing clarification, such as a footnote, on "parameterization checks" and "interoperability." Neither of these terms are defined in this standard or the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican supports MRO NSRF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	

Comment	
Exelon concurs with the comments submitted by the EEI for Question #2. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
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 Regional Standards Committee	
Answer	No
Document Name	
Comment	
Requirement R1 instructs the TP to maintain a requirement document that states the accepted models and the level of detail needed. This requirement is largely covered by MOD-032, R1, and is therefore partially redundant. The Transmission Planning (TP) and Planning Authority (PA) jointly developing dynamic model requirements and processes recognizes that there may be regional transmission system concerns for which different requirements and processes are appropriate. There should be some bare minimum requirements defined in the MOD-026 standard which apply to everyone since the impacts of dynamic events commonly analyzed are not limited by TP or PA area. As an example, the August 14, 2004 blackout impacted much more than one TP or PA area. The models provided as required by R1 have impacts that affect all nearby TPs and PAs – and to some extent all TPs and PAs in the associated AC interconnection (Eastern, Western, Quebec).	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	

The language contained in Requirement R1, subpart 1.2 appears to require electromagnetic transient (EMT) models for all dynamic model requirements and processes regardless of resource type or study need. While the Technical Rationale states that R6 limits this requirement, there is no language within MOD-026-2 that clearly states when these models are required. To address this concern with Requirement R1, we recommend the following edits:
R1. Each Transmission Planner and its Planning Coordinator shall jointly develop dynamic model requirements and processes. The dynamic model requirements and processes shall be made available to the Generator Owner and Transmission Owner by the Transmission Planner, and include at a minimum the following:
1.1. Acceptable positive sequence dynamic models, format, and level of detail, as specified in Requirements R2 and R4;
1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail, where determined to be necessary by the TP and as defined in Requirement R6;
1.3. Acceptance criteria used by the Transmission Planner and/or Planning Coordinator to determine disposition in Requirement R8 including at a minimum the following:
1.3.1. model parameterization checks;
1.3.2. model usability, initialization, and interoperability; and
1.3.3. model submittal requirements.
1.4. Process for Generator Owner or Transmission Owner to provide verified models to the Transmission Planner and/or Planning Coordinator;
1.5. Process by which verified model(s) are submitted to the applicable Planning Coordinator, after the model(s) meets acceptance criteria of Part 1.3; and
1.6. Process for Generator Owner or Transmission Owner to obtain the model(s) contained in the Transmission Planner's and/or Planning Coordinator's database for an existing Facility owned by the Generator Owner or Transmission Owner.
With regard to Part 1.2, the MRO NSRF requests NERC or other industry group develop an acceptable list of electromagnetic transient (EMT) models. Industry has little expertise with EMT. A list of acceptable models, similar to positive sequence models, will reduce barriers and speed EMT model development for applicable functional entities; e.g. Planning Coordinators and Transmission Planners. EMT models tend to be manufacturer specific and guarded by manufacturers from a confidentiality standpoint.
For R1.2, while the technical rationale states that R6 limits the number of EMT models, there is no language within MOD-026-2 that states this. The MRO NSRF recommends that additional language be added to R1.1 and R1.2 to state EMT models as determined and according to the PC and TP joint model process in the requirements. Important requirements cannot be left in the technical rationale.
We recommend replacement of "Transmission Planner" with "Transmission Planner and/or Planning Coordinator" in Requirements R1.3., R1.4., and R1.5.

Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CenterPoint Energy Houston Electric, LLC (“CenterPoint Energy”) agrees that the positive sequence dynamic and electromagnetic transient (EMT) models’ minimum requirements and development of the models’ validation and other processes should be jointly developed by the Transmission Planner (TP) and its Planning Authority (PA). However, EMT models are not used by most Transmission Planners and the transmission software tools to study the entire system with EMT models currently do not exist. CenterPoint Energy believes that the required models’ level of detail should be within the simulation tool's modeling capabilities and reasonable industry practices. The focus should be on the model validation criteria from the field results with a clear list of acceptable test types or system disturbances. The EMT models should only be requested/provided based on proper justification and on a case-by-case basis.

The language in Requirement R1, subpart 1.3.1 that includes model parameterization checks is unclear and could negatively impact entities that do not have the tools or experience to conduct such checks. To address this concern, the SDT should add clarifying language to the Technical Rationale to address how such checks are to be performed in light of software limitations and entity inexperience in this area.

Likes 0	
Dislikes 0	

Response

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw

Answer	No
Document Name	

Comment

Based on the existing generation interconnection process in ERCOT, we recommend changing “Transmission Planner” to “Transmission Planner or Planning Authority” throughout R1 and its sub-requirements. In ERCOT as well as other regions, there are instances in which the Transmission Owner and the Transmission Planner are the same entity. The spirit of the proposed requirement suggests a collaboration of checks and balances to verify modeling accuracy. Requiring a Transmission Owner to send modeling information to itself would not achieve the intended verification of modeling accuracy. Therefore, we advise adding “Planning Authority” in conjunction with “Transmission Planner” for all instances in R1.

The terms used in sub-requirement 1.3 should be clarified with practical descriptions. Please elaborate specifically on the following: “parameterization checks” and “interoperability.” Definitions should be applicable and meaningful to practical Planning studies. It is recommended that the descriptions would be useful in understanding how to benchmark the quality of the models.

Regarding “parameterization checks,” is this analysis intended to be similar to a PSSE DOCU check where each parameter is compared to a typical range? This would be difficult to achieve on User defined models since DOCU ranges are not given for each parameter. Alternatively, are “parameterization checks” meant to validate model parameters and settings against the actual field equipment? Please clarify.

Regarding “interoperability,” does this term indicate that models must be tested in a full case to determine general problems such as crashing, inability to handle certain time steps and/or acceleration factors? Alternatively, does “interoperability” indicate that both types of models (positive sequence and EMT models) should produce the same results when they operate on different software platforms? Please clarify.

Regarding proposed R1.3., attempting to test initialization and interoperability in a full EMT case would require a paradigm shift for Transmission Planners and the Planning Authority within ERCOT. ERCOT does not develop or maintain an official PSCAD case for its Transmission Planners. Cases would need to be built for small individual areas, which would require a substantial undertaking. Instead, it would be more efficient and cost effective for Transmission Planners to validate the EMT models with a simpler, controllable infinite bus test rather than validating them through a full EMT case. Thus, we suggest revising proposed R1.3 to allow Transmission Planners within ERCOT to use this alternative method to validate the EMT models.

Likes 0	

Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
As a Generator Owner and Transmission Owner we will continue to provide requested model data, but at this time there are no NERC approved EMT models with limited software/expertise.	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	No
Document Name	
Comment	
The language in Requirement R1, subpart 1.2 appears to require electromagnetic transient (EMT) models for all dynamic model requirements and processes regardless of resource type or study need. Would the requrement to have EMT models also apply to double-fed induction generators (DFIG)? In addition, National Grid supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports EEI and NAGF comments to R1, and as noted particularly in EEI’s comments that address concern with subpart1.3.1 to include parameterization check and the negative impact to entities.	

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

NERC MOD-026-1 and MOD-027-1 standards cover models used in BES level studies, while EMT models are used for specialized equipment studies. BPA does not believe it is appropriate to require EMT model validation as a part of the MOD-026 and MOD-027 standards. BPA recommends a separate standard to address EMT modeling ourside of MOD-026 and MOD-027.

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	No
Document Name	
Comment	

WEC Energy Group supports EEI and NAGF comments.

- Need to add a sub requirement "Acceptable protective relay models, format and level of detail."
- Need to state EMT models are only required for inverter based resources.
- Need to state that the acceptable models are from industry standards (i.e. IEEE 421.5 for exciters) clearly definded in generic file format (text file, spreadsheet), specifically not in a specific's software proprietry file format.

Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	

The SDT proposal makes use of obsolete Functional Entity references to Planning Authority instead of Planning Coordinator. This comment applies to all Planning Authority references throughout the proposed standard.

It is unclear why the Planning Authority (Coordinator) is being added to this requirement when the existing MOD-026 & 027 standards do not apply to this function. Further, the aspect of joint development of dynamic model requirements is redundant with MOD-032.

As currently worded, the Time Horizon appears to be applicable to both Long-Term Planning (joint verification of dynamic models [see MOD-032]) and Operations Planning (the portion more consistent with currently approved MOD-027 & 027).

Likes 0	
Dislikes 0	

Response

Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.

Answer	No
Document Name	

Comment

Portland General Electric Company supports the comments provided by EEI.

Likes 0	
Dislikes 0	

Response

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	No
Document Name	

Comment

Xcel Energy generally supports the comments of EEI. Below are Xcel Energy comments that indicate additional or differing concerns.

It is Xcel Energy's belief that EMT models may not always be attainable by GOs from equipment manufacturers. EMT models are not generic and are often considered confidential by manufacturers. A requirement should not be placed on TPs to place a requirement on GOs to provide information that may not be attainable from the equipment manufacturers. Furthermore, if the EMT models are to remain a requirement then the language in R1 does not make it clear that EMT models are only required for FACTS devices, IBRs, LCC HVDC, and VSC HVDC. The language of R1 appears to require EMT models for all generation.

Likes 0	
Dislikes 0	

Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Derek Brown, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) to question #2.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

The language contained in Requirement R1, subpart 1.2 appears to require electromagnetic transient (EMT) models for all dynamic model requirements and processes regardless of resource type or study need. While the Technical Rationale states that R6 limits this requirement, there is no language within MOD-026-2 that clearly states when these models are required. Additionally, the Planning Coordinator should be included in subparts 1.3, 1.4 and 1.6.

Next, the language in R1, subpart 1.3.1 that includes model parameterization checks is unclear and could negatively impact entities that do not have the tools or experience to conduct such checks. To address this concern, the SDT should provide clarifying language to the Technical Rationale to address how such checks are to be performed in light of software limitations and entity inexperience in this area.

To address this concern with Requirement R1, we recommend the following edits:

R1. Each Planning **Coordinator, in conjunction with its Transmission Planner,** shall jointly develop dynamic model requirements and processes. The dynamic model requirements and processes shall be made available to the Generator Owner and Transmission Owner by the **Planning Coordinator**, and include at a minimum the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

1.1. Acceptable positive sequence dynamic models, format, and level of detail**, as specified in Requirements R2 and R4**;

1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail, **where determined to be necessary by the Transmission Planner and Planning Coordinator, through a formal analysis, conducted by the responsible Transmission Planner, that indicates their inability to conduct accurate simulations with preexisting Transmission Planner tools that reflect and assess BES reliability performance. (e.g., areas with IBR growth impacts or IBRs installed in areas with low short circuit strength)**;

1.3. Acceptance criteria used by the Transmission Planner **and/or Planning Coordinator** to determine disposition in Requirement R8 including at a minimum the following:

1.3.1. model parameterization checks;

1.3.2. model usability, initialization, and interoperability; and

1.3.3. model submittal requirements.

1.4. Process for Generator Owner or Transmission Owner to provide verified models to the Transmission Planner **and/or Planning Coordinator**;

1.5. Process by which verified model(s) are submitted to the applicable Planning **Coordinator**, after the model(s) meets acceptance criteria of Part 1.3; and

1.6. Process for Generator Owner or Transmission Owner to obtain the model(s) contained in the Transmission Planner's **and/or Planning Coordinator's** database for an existing Facility owned by the Generator Owner or Transmission Owner.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment

Comments: The language contained in Requirement R1, subpart 1.2 appears to require electromagnetic transient (EMT) models for all dynamic model requirements and processes regardless of resource type or study need. While the Technical Rationale states that R6 limits this requirement, there is no language within MOD-026-2 that clearly states when these models are required. Additionally, the Planning Coordinator should be included in subparts 1.3, 1.4 and 1.6.

Next, the language in R1, subpart 1.3.1 that includes model parameterization checks is unclear and could negatively impact entities that do not have the tools or experience to conduct such checks. To address this concern, the SDT should provide add clarifying language to the Technical Rationale to address how such checks are to be performed in light of software limitations and entity inexperience in this area.

To address this concern with Requirement R1, we recommend the following edits:

R1. Each Planning **Coordinator, in conjunction with its Transmission Planner,** shall jointly develop dynamic model requirements and processes. The dynamic model requirements and processes shall be made available to the Generator Owner and Transmission Owner by the **Planning Coordinator**, and include at a minimum the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

1.1. Acceptable positive sequence dynamic models, format, and level of detail**, as specified in Requirements R2 and R4**;

1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail, **where determined to be necessary by the TP and as defined in Requirement R6**;

1.3. Acceptance criteria used by the Transmission Planner **and/or Planning Coordinator** to determine disposition in Requirement R8 including at a minimum the following:

1.3.1. model parameterization checks;

1.3.2. model usability, initialization, and interoperability; and

1.3.3. model submittal requirements.

1.4. Process for Generator Owner or Transmission Owner to provide verified models to the Transmission Planner **and/or Planning Coordinator**;

1.5. Process by which verified model(s) are submitted to the applicable Planning **Coordinator**, after the model(s) meets acceptance criteria of Part 1.3; and

1.6. Process for Generator Owner or Transmission Owner to obtain the model(s) contained in the Transmission Planner's and/or Planning Coordinator's database for an existing Facility owned by the Generator Owner or Transmission Owner.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

More explanation for why the Planning Authority (PA) is involved in the development of the dynamic model requirements and processes should be explained since they have no other major part of the standard (mostly applies to the TOs, GOs, and TPs). ATC suggests that R1 should apply only to the TP so they can have wider discretion in writing their process to meet their requirements. Perhaps the PA can coordinate and review each of their TPs processes before they are finalized, rather than jointly work on it.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	No
Document Name	

Comment

AZPS does not agree that EMT models should be required for the following reasons:

The EMT modeling requirement seems excessive for this application as there has not been sufficient justification of why this level of detail is required. Concerns for large-signal disturbance behavior are already being addressed by recommended practices such as PRC-024 and the NERC "BPS-

Connected Inverter-Based Resource Performance Reliability Guideline." While these do not directly address modeling, they require that the type of behavior that was witnessed during the Blue Cut fire is mitigated. Since we are currently setting protection to be broad enough to ride through these disturbances, requiring EMT models in addition to positive sequence models would add significant cost and time to model verification without creating additional reliability.

In addition, AZPS also agrees with the following comment that has been submitted by EEI: "The language contained in Requirement R1, subpart 1.2 appears to require electromagnetic transient (EMT) models for all dynamic model requirements and processes regardless of resource type or study need. While the Technical Rationale states that R6 limits this requirement, there is no language within MOD-026-2 that clearly states when these models are required."

AZPS does not agree with the inclusion of subpart 1.3.1. Previous MOD 026 model criteria was intentionally vague in order to leave room for engineering judgement when conducting the model validation. No model is a facsimile of reality, and there needs to be room for creating a model that adequately reflects reality based on the judgement of the person conducting the model validation. For this reason, AZPS requests further information regarding the intent of subpart 1.3.1.

In addition, AZPS supports the following comment that has been submitted by EEI: "The language in R1, subpart 1.3.1 that includes model parameterization checks is unclear and could negatively impact entities that do not have the tools or experience to conduct such checks. To address this concern, the SDT should provide clarifying language to the Technical Rationale to address how such checks are to be performed in light of software limitations and entity inexperience in this area.

Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	

AECI agrees with EEI's comments:

The obligations related to Requirement R2, subpart 2.3 as it relates to GO and TO modifications to protection systems synchronous generation identified in Section 4.2.1 or 4.2.2 or a synchronous condenser identified in Section 4.2.4.1 should be clarified. Specifically, the SDT should clarify the timeframe that will be required to complete and submit updated models to the TP after protection system changes.

EEI requests similar clarifications regarding GO and TO obligations as it relates to Requirement R3, subpart 3.3.

Additionally, the Planning Coordinator should be added to these requirements since they share in the development of the planning models.

Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	

Answer	No
Document Name	
Comment	

Requirement R1 would require the TP to maintain model requirement documentation that outlines the accepted models and the level of detail needed. A concern is that parts of Requirement 1 (such as 1.1 and 1.2) are largely covered by MOD-032, R1 and are therefore partially redundant.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

FE agrees with EEI's comments.

The language contained in Requirement R1, subpart 1.2 appears to require electromagnetic transient (EMT) models for all dynamic model requirements and processes regardless of resource type or study need. While the Technical Rationale states that R6 limits this requirement, there is no language within MOD-026-2 that clearly states when these models are required. Additionally, the Planning Coordinator should be included in subparts 1.3, 1.4 and 1.6.

Next, the language in R1, subpart 1.3.1 that includes model parameterization checks is unclear and could negatively impact entities that do not have the tools or experience to conduct such checks. To address this concern, the SDT should provide add clarifying language to the Technical Rationale to address how such checks are to be performed in light of software limitations and entity inexperience in this area.

To address this concern with Requirement R1, we recommend the following edits:

R1. Each Planning **Coordinator, in conjunction with its Transmission Planner,** shall jointly develop dynamic model requirements and processes. The dynamic model requirements and processes shall be made available to the Generator Owner and Transmission Owner by the **Planning Coordinator**, and include at a minimum the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

1.1. Acceptable positive sequence dynamic models, format, and level of detail**, as specified in Requirements R2 and R4**;

1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail, **where determined to be necessary by the TP and as defined in Requirement R6**;

1.3. Acceptance criteria used by the Transmission Planner **and/or Planning Coordinator** to determine disposition in Requirement R8 including at a minimum the following:

1.3.1. model parameterization checks;

1.3.2. model usability, initialization, and interoperability; and

1.3.3. model submittal requirements.

1.4. Process for Generator Owner or Transmission Owner to provide verified models to the Transmission Planner **and/or Planning Coordinator**;

1.5. Process by which verified model(s) are submitted to the applicable Planning **Coordinator**, after the model(s) meets acceptance criteria of Part 1.3; and

1.6. Process for Generator Owner or Transmission Owner to obtain the model(s) contained in the Transmission Planner's **and/or Planning Coordinator's** database for an existing Facility owned by the Generator Owner or Transmission Owner.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

R1 1.2 EMT models are not used by most Transmission Planners. This addition will add significant cost to generation owners. The EMT models should only be provided based on appropriate justification and on a case-by-case basis. The financial impacts to generator operators to provide these models for every applicable facility is not justified. Positive sequence generic models if properly populated and verified are adequate for most transmission studies. The transmission software tools to study the entire system with EMT models do not exist.

Requirements should be detailed in this standard. Utilities that operate in multiple regions will be required to submit different levels of detail to comply with this Standard. The wording in R1.1, R1.2, and R1.3 gives the TP authority to request data above the needed intent of the Standard (Performance Curves, Response Characteristics, Response Times etc.).

The specific acceptance criteria for the model in R1.1, 1.2, and 1.3 should be developed by the industry modeling experts or remain the same as existing MOD-026 and 027 standards.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment

Requirement R1 instructs the TP to maintain a requirement document that states the accepted models and the level of detail needed. This requirement is largely covered by MOD-032, R1 and is therefore partially redundant.

Likes 0	

Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
: R1 1.3 States the acceptance criteria used by Transmission Planner for only updated models. It does not state the requirement for new models.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Each TP is allowed to establish and dictate their own methods, requirements, processes, and acceptance criteria without constraints, boundaries, or need of consistency with other industry participants. The allowance of arbitrary requisites implies the requirement has no technical basis or justification. This results in Generator Owners, especially those in multiple TP areas, provide various types of data in different formats based upon TP preferences only, with no basis of demonstrated reliability improvement. R1.2, and other relevant sections, allows the TP to mandate EMT models without sufficiently demonstrating that EMT models are needed in addition to positive sequence models.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Manitoba Hydro agrees that the positive sequence dynamic and electromagnetic transient (EMT) models minimum requirements and development of models' validation and other processes should be developed by the Planning Authority and Transmission Planner. However, we think that the required models level of detail should be within the simulation tool's modeling capabilities to avoid the need for developing user's defined models (which may add	

a lot of complexity and overhead to developing these models with some level of approximation which makes it more difficult to share with other PA and more difficult to maintained and validated). Also, the model's level of details should be within the reasonably industrial practice as some of the levels of detail may not be possible to present due to the vender's trade secret. The focus should be on the model validation criteria from the field results with a clear list of acceptable test types or system disturbances.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Each TP is allowed to establish and dictate their own methods, requirements, processes, and acceptance criteria without constraints, boundaries, or need of consistency with other industry participants. The allowance of arbitrary requisites implies the requirement has no technical basis or justification. This results in Generator Owners, especially those in multiple TP areas, providing various types of data in different formats based upon TP preferences only, with no basis of demonstrated reliability improvement.

R1.2, and other relevant sections, allows the TP to mandate EMT models without sufficiently demonstrating that EMT models are needed in addition to positive sequence models.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

The language contained in Requirement R1, subpart 1.2 appears to require electromagnetic transient (EMT) models for all dynamic model requirements and processes regardless of resource type or study need. While the Technical Rationale states that R6 limits this requirement, there is no language within MOD-026-2 that clearly states when these models are required. Additionally, the Planning Coordinator should be included in subparts 1.3, 1.4 and 1.6.

Next, the language in R1, subpart 1.3.1 that includes model parameterization checks is unclear and could negatively impact entities that do not have the tools or experience to conduct such checks. To address this concern, the SDT should provide add clarifying language to the Technical Rationale to address how such checks are to be performed in light of software limitations and entity inexperience in this area.

To address this concern with Requirement R1, we recommend the following edits:

R1. Each **Transmission Planner and its** Planning **Authority Coordinator, in conjunction with its Transmission Planner,** shall jointly develop dynamic model requirements and processes. The dynamic model requirements and processes shall be made available to the Generator Owner and Transmission Owner by the **Transmission PlannerPlanning Coordinator**, and include at a minimum the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

1.1. Acceptable positive sequence dynamic models, format, and level of detail**, as specified in Requirements R2 and R4**;

1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail, **where determined to be necessary by the TP and as defined in Requirement R6**;

1.3. Acceptance criteria used by the Transmission Planner **and/or Planning Coordinator** to determine disposition in Requirement R8 including at a minimum the following:

1.3.1. model parameterization checks;

1.3.2. model usability, initialization, and interoperability; and

1.3.3. model submittal requirements.

1.4. Process for Generator Owner or Transmission Owner to provide verified models to the Transmission Planner **and/or Planning Coordinator**;

1.5. Process by which verified model(s) are submitted to the applicable Planning **AuthorityCoordinator**, after the model(s) meets acceptance criteria of Part 1.3; and

1.6. Process for Generator Owner or Transmission Owner to obtain the model(s) contained in the Transmission Planner's and/or Planning Coordinator's database for an existing Facility owned by the Generator Owner or Transmission Owner.

Likes 0	
Dislikes 0	
Response	

Jack Stamper - Clark Public Utilities - 3

Answer	No
Document Name	

Comment

R1.2 should be changed to: Acceptable electromagnetic transient (EMT) models, format, and level of detail if the Transmission Planner area has applicable units of inverter based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2.

Many Transmission Planners do not have any applicable units that are subject to Requirement 6 so there is no need for these Transmission Planners to have acceptable EMT models. Otherwise, Transmission Planners will need to argue during audits that there is no need for these provisions in their modeling requirements. However, the current language requires that Transmission Planners have EMT modeling requirements even if the modeling requirements will not be utilized.

Likes 0	

Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
Agree with comments submitted by BPA.	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	

In MOD-026-1 and MOD-027-1, the TP only needs to provide information to the GO when the GO requests the information. Now, under MOD-026-2, the TP "shall jointly develop dynamic model requirements and processes" and the documentation "shall be made available to the Generator Owner and Transmission Owner by the Transmission Planner" regardless of whether the information is requested by the GO or TO. As a vertically integrated utility, such processes do not add value equal to the administrative burden to the TP in creating, archiving, and tracking said processes.

Furthermore, the changes unnecessarily pull in requirement activities for the Planning Coordinator (the standard incorrectly references Planning Authority, which NERC has moved away from); under MOD-032, the Planning Coordinator has the opportunity to work with the Transmission Planner on data items; the

approach for this 'TP Model Spec and Process' as found in the current MOD-026 and MOD-027 standards are preferable to this new language.

Furthermore, while the current standards specify a minimum and appropriate level of initialization tests and criteria, the new standard does not, which could lead to poor acceptance testing by the Transmission Planner.

The concept of model interoperability (1.3.2) is a concept not well discussed in the standard or elsewhere. It is recommended either this concept be better supported or removed altogether.

For the 1.2. requirement for Transmission Planners to have EMT specifications, this will add burden to those Transmission Planners who do not have IBRs or other devices covered under the proposed MOD-026-2 Requirements R4 or R5, yet would still be required to develop and maintain a specification for models that the Transmission Planner does not have in its footprint. The applicability for this requirement needs to be better tailored to allow the Transmission Planner to not fall under this requirement if it does not have such equipment that requires this. Furthermore, upon review of the SARs, none of the SARs propose any new EMT modeling requirements, so this R1.1.2 and R6 addition appears to be outside the scope of the SARs for the MOD-026/27 standard revisions.

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
The model requirements are too vague. The SDT needs to clarify the criteria/requirements that are to be utilized for modeling especially because there are so many different software applications that are being used. It is unclear on what evidence we would present for R1.2 Also, because the models can be very different, how would the coordination happen between WECC and the TP.	
Likes 0	
Dislikes 0	
Response	
James Howell - Southern Company - Southern Company Generation - 5	
Answer	No
Document Name	
Comment	
See Southern Company Comments	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
• ERCOT is concerned with overlap between the proposed R1 language and the requirements in MOD-032-1. MOD-026-2, R1 states: "Each Transmission Planner and its Planning Authority shall jointly develop dynamic model requirements and processes." MOD-032-1, R1 states: "Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements. . . ." ERCOT proposes to leave the requirement to *develop* models in MOD-032-1 and focus MOD-026-2 on model *verification,* as approved in the SARs.	

- In supbpart 1.3.1, ERCOT believes the term “parameterization” may cause problems. The PC/TP should not have to ensure a model uses proper parameters; instead, the GO/TO should have to demonstrate it used proper model parameters. A TP’s acceptance criteria should focus on model performance rather than its parameters. Further, acceptance criteria under 1.3 should include a check for consistency between Electromagnetic Transient (EMT) and positive sequence model performance.
- In subpart 1.3.2, ERCOT believes the term “interoperability” is ambiguous and suggests either removing the term or providing additional clarification.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	

Comment

We believe the Transmission Planner and Planning Coordinator already have a place where they describe modeling data requirements in MOD-032. We feel that R1.1 and R1.2 do not belong in MOD-026 but in MOD-032. The remaining R1.3 – R1.6 are OK, though there may be some overlap with the requirements of MOD-032 that the SDT should look into. Also note that the R1.2 requirement for the TP to define EMT “models, format and level of detail” seems to overlap somewhat with R6, in particular R6.3.

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

MOD-026-2 R1 states that the Transmission Planner and Planning Authority jointly develop requirements and processes, but only identifies Transmission Planner in the rest of the standard. In some regions the Planning Authority maintains dynamic models, therefore LCRA TSC suggests the SDT adopt language similar to TPL-007-2 R1 stating the Planning Authority, in conjunction with its Transmission Planner(s) identify individual and joint responsibilities of the Planning Authority and Transmission Planner(s) in the Planning Authority’s planning area. This change would lead to removing Transmission Planner in the requirements and replacing that with “responsible entity” throughout the standard. LCRA TSC also suggests providing clarification, such as a footnote, on “parameterization checks” and “interoperability.” Neither of these terms are defined in this standard or the NERC Glossary of Terms.

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 has concern that there is no language within MOD-026-2 to limit the number of EMT models to be developed. We recommend that additional language be added to R1.1 and R1.2 to state EMT models "as determined and according to the PA and TP joint model process in the requirements". Although discussed in the technical rationale, important requirements cannot be left solely in the technical rationale.

Southern Company believes that select facilities identified by the regional TP/PC for EMT modeling be limited to facilities reaching commercial operation after the standard is ratified. This will provide all parties with compliance responsibilities and obligations to successfully prepare for the new requirements, specifically:

- Newly specified and purchased equipment can be purchased with the monitoring provisions, engineering models information, and testing adequate to prove the model is accurate, and meets the standard requirements.
- The required OEM participation can be part of the equipment specification at the time of purchase – at this time the OEM is open to providing what is both specified and needed.
- The new equipment can be provisioned and functionally capable of providing the best possible ride through capabilities to large system disturbances.
- The verified and validated modeling activities can only be then planned accordingly and delivered at the time of commissioning, as required.

Existing equipment (operational back to 2015) should not be included in the scope of the new modeling requirements. Experience has shown that EMT modeling of older plants is very difficult and, in some cases, impossible to conduct and meet current requirements. In our opinion, application of these modeling requirement changes is not worth the effort or cost.

We suggest that an acceptable list of electromagnetic transient (EMT) models be developed. Industry has little expertise with EMT. A list of acceptable models, similar to positive sequence models, will reduce barriers and speed EMT model development for applicable functional entities; e.g. Planning Authorities and Transmission Planners. EMT models tend to be manufacturer specific and guarded by manufacturers from a confidentiality standpoint.

Southern Company concurs with EEI's comments on this item: the TP/PA should decide where EMT models are needed.

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; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	No
Document Name	
Comment	
Processes described will not directly address root causes of the Odessa IBR tripping event(s) in May of 2021, which at least in part resulted from failure to modify OEM standard inverter protection settings. Specific direction for verification tests (alternative to the proposed recording of field responses to frequency and voltage excursions) should be provided.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
The Transmission Planning (TP) and Planning Authority (PA) jointly developing dynamic model requirements and processes recognizes that there may be regional transmission system concerns for which different requirements and processes are appropriate. There should be some bare minimum requirements defined in the MOD-026 standard which apply to everyone since the impacts of dynamic events commonly analyzed are not limited by TP or PA area. As an example, the August 14, 2004 blackout impacted much more than one TP or PA area. The models provided as required by R1 have impacts which affect all nearby TPs and PAs – and to some extent all TPs and PAs in the associated AC interconnection (Eastern, Western, Quebec).	
Likes 0	
Dislikes 0	
Response	
Aric Root - CMS Energy - Consumers Energy Company - 4	
Answer	Yes
Document Name	
Comment	
Consumers Energy is fine with this Requirement, however it would be good to get the Generator Owners perspective on this dynamic model requirements and processes.	

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP has no objections to the language proposed for R1.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
WECC agress with the language and purpose of the Requirement. However, WECC suggests changing Planning Authority to Planning Coordinator to align with current terminology.	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Consumers Energy is fine with this Requirement, however it would be good to get the Generator Owners perspective on this dynamic model requirements and processes.	
Likes 0	

Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Consumers Energy is fine with this Requirement; however, it would be good to get the Generator Owners perspective on this dynamic model requirements and processes.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation agrees with the proposed language. 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 proposed language.	

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	

SPP can initially support the proposed language, however, we do have concerns pertaining to Requirement R1. The first concern is that standards do not require an independent Power Producer to provide proof of its Transmission Planner assignment? From our perspective, this proof should be a requirement to increase coordination.

Additionally, performance testing standards (MOD-026/27) are not tied to the reporting requirement of MOD-032, and SPP recommends these items should be added to the MOD-032 standard as well.

Finally, the last concern pertains to the collection of modeling data such as the Phase Look Loop Data (PLL) for our Short Circuit Ratio (SCR) screening Analysis, which access to such data will help determine the need for an Electromagnetic Transient (EMT) study. Data collection has been a challenge for SPP. Often times the GO clasims they do not have access to a portion of the SCR screening data and will need the vendor to provide it. Currently the vendor is not an applicable entity. Morover, there has been issues with OEM vendors not wanting to share the data due to proprietary interests. In addition to, sub-part 1.3 should include the PC as RTO's should develop their own model requirements for dynamics and EMT.

In summary, SPP suggests the drafting team:

- create language that would require the IPP to communicate modeling data effective and efficiently with the TP
- consider aligning the the performance testing standards (MOD-026/27) with the reporting requirement (MOD-032) in reference to modified/material changes
- create proposed language that will require the OEM vendors to share need model data to conduct SCR screenings as well as the EMT studies Finally, we suggest that the drafting team take into consideration of creating proposed language that will require the OEM vendors to share

need model data to conduct our SCR screenings as well as the EMT studies.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
John Pearson - ISO New England, Inc. - 2	
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	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Pam Syrjala, Salt River Project, 5, 3, 1, 6; Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Dwanique Spiller, Berkshire Hathaway - NV Energy, 5; - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 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	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Buckeye Power, Inc. - 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), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE agrees on the approach to revising Requirement R1. Texas RE does, however,recommend enhancing the language of Requirement R1 to include more guidance on how the "dynamic model requirements and processes shall be made available". In Requirement Part 1.6, Texas RE recommends including the Planning Authority's database from which the GO or TO could obtain the model for an existing Facility owned by the GO or TO.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	

Comment	
Consistent with the evolution of other currently effective NERC standards, “Planning Coordinator” should be used in lieu of “Planning Authority” in R1 and Applicability listing 4.1.3.	
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	
The ITC Standards Under Development Team has received no response to submit from the Standard Owners	
Likes 0	
Dislikes 0	
Response	

3. Do you agree the language proposed in MOD-026-2 Requirements R2 and R3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	

Requirements 2.3 and 3.3 are essentially a repeat of the protection system/generator limiter requirements of PRC-019. In PRC-019, GOs and TOs are required to submit this data using the traditional "D" curve which plots a generator capabilities, all generator limiters, and all generator protection system responses including loss of field and volts per hertz. There is no modeling need for any of the protection indicated. If the SDT believes that the Transmission Planner needs to know the performance characteristics of over- and under-voltage, stator and field overcurrent, loss of field, outof-step, and volts per hertz protection or any of the other protection system elements enabled for generator protection, that should be part of the protection system coordination standard, PRC-019.

The SAR indicates that voltage control behavior during large disturbance conditions is not verified. That is not so. PRC-024 requires generators to meet region-specific voltage and frequency ride through requirements and to provide the settings for it voltaage and frequecy protection to Transmission Planners. In addition, PRC-006 requires the provision of UFLS tripping data that includes generator frequecy ride through trip settings. Adding these to MOD-026 does nothing more than make Generator Owners prove compliance with multiple standards for the same action. This is not in accordance witht the efficiency goals of the NERC Standards development which included consolidation identical actions in multiple standards into a single standard to avoid unnecessary duplication of efforts.

I don't think Generator Owners would have a problem providing Transmission Planners with an entire list of all generator Protection System elements that are enabled, however, for ease of implementation, that would be better complied with and evidenced if the requirements were all under one standard.

Consider either putting R2.3 and 3.3 requirements under PRC-019 (my perferred approach) or eliminating PRC-019 and putting all generator and synchronous condenser protection system coordination and modeling under the new MOD-026.

Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	

The obligations related to Requirement R2, subpart 2.3 as it relates to GO and TO modifications to protection systems synchronous generation identified in Section 4.2.1 or 4.2.2 or a synchronous condenser identified in Section 4.2.4.1 should be clarified. Specifically, the SDT should clarify the timeframe that will be required to complete and submit updated models to the TP after protection system changes.

EEI requests similar clarifications regarding GO and TO obligations as it relates to Requirement R3, subpart 3.3.

Additionally, the Planning Coordinator should be added to these requirements since they share in the development of the planning models.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

The modeling of protective elements such as field overcurrent, V/Hz, over voltage, and loss of field is not appropriate if an excitation system incorporates limiters designed/tested/verified to prevent such operation as documented via PRC-019. Including protection models in such cases will lead to erroneous tripping in the simulation of dynamic events where actual limiter operation would prevail. The best case scenario for including both limiter and protection models is that protection models are redundant and a waste of effort and computer/database resources. Some issues to be considered are:

- Protection models can be very precise whereas limiter models are approximations. Models will normally not exhibit the same margins of coordination as the actual equipment.
- V/Hz and overvoltage limiter models are currently not available in commercial simulation packages and standard model development takes several years. Including protection models instead of limiter models does not represent unit behavior.
- Field overcurrent protection (possibly other functions) in most cases is integrated and coordinated with the limiter in the excitation system software and would only operate in an excitation control system failure scenario and therefore should not be modeled.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

The basis for the SAR was the deficiency of dynamic models to represent ride-through operation modes of IBRs such as momentary cessation. There is no justification in the SAR to expand the scope of the standard to include excitation limiters and Protection System settings as field verified models. There is no demonstrated reliability gap, no tangible justification of how a reliability gap will be closed, and no technical foundation in the SAR to justify the need for field validated models of limiters and protection. The justification provided in the Rationale for Requirement 3 makes unsubstantiated statements about exacerbating grid disturbances potentially causing cascading failures, while the Rationale ignores the technical basis used for the development of the PRC Standards such as PRC-019, -024, -025, -026, etc. If the technical basis for those standards is valid, the Rationale for R3 is inaccurate.

For example, the no-trip boundaries of PRC-024 is the criteria for the TP to design and plan the system operation; if the operation of protection elements occurs outside the no-trip zone, this operation should be irrelevant to the TP process, because this is an unacceptable operating region and the reason why the Protection System exists. There are no industry established acceptance criteria used to identify what constitutes a "validated" excitation limiter model (consistent with practices used to validate dynamic models and parameters), especially when the limiter settings are outside the boundaries of reachable or desirable operation under normal conditions. Within dynamic model software packages, excitation limiter models do not have full representation of OEM equipment suppliers that are actively in service. Prior to mandating requirements in a standard, there should be independent, published studies of prototype efforts where the effectiveness and actual benefits of improved reliability are demonstrated and quantified in real numbers (rather than generic language) providing a true cost to benefit analysis.

For effectiveness, Protection System model development must accommodate all installed devices and protection elements regardless of equipment or technology. It is not desirable to have the Protection System model development process becoming the preeminent driver of setting development or the bottleneck of Protection System settings implementation, which is at risk of happening with this requirement. A more effective means to implement, the industry should first develop acceptable, consistent methods for the TP to receive excitation limiter and protection device setting characteristics. Then, the TP can develop models as needed or justified. The GO should not have the obligation to develop limiter or protection validated models for the TP. There are no established criteria developed to determine when an outer-loop controller impacts dynamic volt/volt-ampere reactive (VAR) performance.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

Manitoba Hydro does not agree with including 2.1, 2.2, and 2.3 as minimum modeling requirements. We think that it is up to the TP / PA to determine the required minimum modeling requirements and level of the modeling details as stated in R1 (1.1). If the TP / PA determines that some or all of these listed minimum requirements are needed to include in the model base or the type of performed studies they can include these as part of the R1 (1.1, level of detail). The level of detail and minimum requirements may change based on the type of studies and studies issues. The model requirements for the new facilities may differ from the in-service facilities and some in-service facilities may require a different level of detail. Therefore, the model(s) level of detail should be left to the TP / PA.

The R2 part 2.3 should be limited to the applicable protection models when requested by the Planning Authority and the Transmission Planner. Some of these models stated in 2.2 and 2.3 may not be available in the standard library of the required simulation tools (developing user's defined models) and they may not add any additional benefit to the modeling accuracy and validation process. Also, it could be very hard to validate the accuracy of these models. No point in adding more information to the models if it is not possible to test them with a reasonably overhead cost.

Alternately,

We recommend replacing 2.1, 2.2, and 2.3 with the following:

2.1 The verified model(s) and accompanying information shall include the minimum model requirements and level of detail as stated in R1 part 1.1 and part 1.3 by their TP / PA.

Or

The verified model(s) and accompanying information shall include the minimum model requirements as stated by their TP / PA in R1 part 1.1 and part 1.3 which may include the following:

2.1. Manufacturer, model number (if available), and type of generator/synchronous condenser, excitation system hardware, and Protection System(s) of

Part 2.3;

2.2. Model(s) representing the generator/synchronous condenser, and associated excitation system including voltage regulator, impedance compensation, power system stabilizer, excitation limiters, and outer-loop controls which impact dynamic volt/volt-ampere reactive (VAR) performance;

2.3. Model(s) representing enabled Protection Systems that directly trip the generator/synchronous condenser. Protection Systems that shall be modeled include over- and under-voltage, stator and field overcurrent, loss of field, out-of-step, and volts per hertz protection; and

Manitoba Hydro does not agree with including 3.1, 3.2, and 3.3 as minimum modeling requirements. We think that it is up to the TP / PA to determine the required minimum modeling requirements and level of the modeling details as stated in R1 (1.1). If the TP / PA determines that some or all these listed minimum requirements are needed to include in the model base or the type of performed studies they can include these as part of the R1 (1.1, level of detail).

The R3 part 3.3 should be limited to the applicable protection models when requested by the Planning Authority and the Transmission Planner.

Alternately,

We recommend replacing 3.1, 3.2, and 3.3 with the following:

3.1 The verified model(s) and accompanying information shall include the minimum model requirements and level of detail as stated in R1 part 1.1 and part 1.3 by their TP / PA.

Or

The verified model(s) and accompanying information shall include the minimum model requirements as stated by their TP / PA in R1 part 1.1 and part 1.3 which may include the following:

3.1. Manufacturer, model number (if available), type of turbine, type of governor, mode of operation, and Protection System(s) of Part 3.3;

3.2. Model(s) representing the turbine, governor control system, load controller, and other outer loop controls that override the governor response or modes of operation that limit frequency response, but exclude automatic generation control;

3.3. Model(s) representing enabled Protection Systems that directly trip the turbine-generator. Protection Systems that shall be modeled include over- and under-speed, and over- and under-frequency;

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

The basis for the SAR was the deficiency of dynamic models to represent ride-through operation modes of IBRs such as momentary cessation. There is no justification in the SAR to expand the scope of the standard to include excitation limiters and Protection System settings as field verified models. There is no demonstrated reliability gap, no tangible justification of how a reliability gap will be closed, and no technical foundation in the SAR to justify the need for field validated models of limiters and protection. The justification provided in the Rationale for Requirement 3 makes unsubstantiated statements about exacerbating grid disturbances potentially causing cascading failures, while the Rationale ignores the technical basis used for the development of the PRC Standards such as PRC-019, -024, -025, -026, etc. If the technical basis for those standards is valid, the Rationale for R3 is inaccurate. For example, the no-trip boundaries of PRC-024 is the criteria for the TP to design and plan the system operation; if the operation of protection elements occurs outside the no-trip zone, this operation should be irrelevant to the TP process, because this is an unacceptable operating region and the reason why the Protection System exists. There are no industry established acceptance criteria used to identify what constitutes a "validated" excitation limiter model (consistent with practices used to validate dynamic models and parameters), especially when the limiter settings are outside the boundaries of reachable or desirable operation under normal conditions. Within dynamic model software packages, excitation limiter models do not have full representation of OEM equipment suppliers that are actively in service. Prior to mandating requirements in a standard, there should be independent, published studies of prototype efforts where the effectiveness and actual benefits of improved reliability are demonstrated and quantified in real numbers (rather than generic language) providing a true cost to benefit analysis. For effectiveness, Protection System model development must accommodate all installed devices and protection elements regardless of equipment or technology. It is not desirable to have the Protection System model development process becoming the preeminent driver of setting development or the bottleneck of Protection System settings implementation, which is at risk of happening with this requirement. A more effective means to implement, the industry should first develop acceptable, consistent methods for the TP to receive excitation limiter and protection device setting characteristics. Then, the TP can develop models as needed or justified. The GO should not have the obligation to develop limiter or protection validated models for the TP. There are no established criteria developed to determine when an outer-loop controller impacts dynamic volt/volt-ampere reactive (VAR) performance.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

: R 2.3 covering tripping by protection system components is crossing over matters already in PRC19 and PRC24

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

BC Hydro is unable to support the current draft of R2 as the requirement to "verify and validate" exciter limiters will severely limit the Generator Owners ability to validate models using system disturbance events as an alternative to staged testing.

Requirement R2 Part 2.4 mandates "validation" of models for excitation limiters, which are among the equipment listed under R2 Part 2.2. In BC Hydro's experience, it is uncommon for system disturbances to result in a large enough response from the excitation system that could be used to validate these limiters. As a result, based on the current R2 draft, a staged test is the only other option for validation of excitation limiter models. It is BC Hydro's interpretation that a staged test with reduced limiter setting will qualify as "validation" per Section 6.2 of the standard (Please confirm whether this interpretation is correct). However, performing a staged test require generating units to be taken out of service, which has associated costs and efforts not necessary under MOD-026-1.

BC Hydro suggests that the requirement to model limiters be moved from R2 Part 2.2 to R2 Part 2.3. In doing so, the requirement to verify the excitation limiter models is maintained but "validation" will not be required. As a result, system disturbance events can be used for validation of system models.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

The limiter models in PSSe may or may not be able to accurately represent all manufacturers functions. The standard needs to acknowledge this deficiency and specifically state that dynamic response matching simulations for limiters is not required to be submitted.

Protection models are in no way required if limiters are being used in the models. Protection works in the systems even if the limiters don't. In simulation, this scenario would never occur so there is no need to submit them. PRC standards are already developed to comply with ride-through requirements. This requirement is also pushing generator owners to purchase PSSe or PSLF software or to strictly rely on vendors to perform all this work.

Recommended changes:

1 - Remove the need to supply protection models.

2 - Make PRC-019 and PRC-024 documents available to TPs so they can populate models as needed.

3 - Specify simulated response of limiter models do not need to match test data for limiters.

Simply provide limiter settings for OEL, UEL, V/Hz, and SCL and allow the TP to determine study impacts or industry could develop simplified limiter models for use with setpoints

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

FE agrees with EEI's comments:

The obligations related to Requirement R2, subpart 2.3 as it relates to GO and TO modifications to protection systems synchronous generation identified in Section 4.2.1 or 4.2.2 or a synchronous condenser identified in Section 4.2.4.1 should be clarified. Specifically, the SDT should clarify the timeframe that will be required to complete and submit updated models to the TP after protection system changes.

EEI requests similar clarifications regarding GO and TO obligations as it relates to Requirement R3, subpart 3.3.

Additionally, the Planning Coordinator should be added to these requirements since they share in the development of the planning models.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

AECI agrees with EEI's comments:

The obligations related to Requirement R2, subpart 2.3 as it relates to GO and TO modifications to protection systems synchronous generation identified in Section 4.2.1 or 4.2.2 or a synchronous condenser identified in Section 4.2.4.1 should be clarified. Specifically, the SDT should clarify the timeframe that will be required to complete and submit updated models to the TP after protection system changes.

EEI requests similar clarifications regarding GO and TO obligations as it relates to Requirement R3, subpart 3.3.

Additionally, the Planning Coordinator should be added to these requirements since they share in the development of the planning models.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	No
Document Name	

Comment

AZPS does not support subparts 2.2, 2.3 and 2.4 and requests that the STD provide further clarification on what is expected to validate limiter models.

To perform a staged or measured test with as-left limiter values is impractical. The coordination of limiter function is already maintained in PRC-24 and PRC-19, therefore under most circumstances limiters will not come into play with proper coordination for most system disturbance events. In addition, the limiter models are not always easily available, especially in the case of legacy units. All limiters in the excitation system would need to be modeled in order to prevent nuisance trips from the newly implemented generator protection models. For these reasons, the amount of effort required to model and validate limiter models is large and will not significantly contribute to improved system reliability.

Subpart 2.3 is also impractical as PRC 019 and PRC 024 already require a review of protection settings to prevent unnecessary tripping of units. Creating generator protection models from protection settings would still be a significant amount of work with very little reliability benefit.

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation does not agree with the expanded modeling requirements. While we understand there may be value in developing and providing a model for non-linear protection functions, We don't see the value in developing models for definite-time relay settings rather than just providing those settings. Constellation feels that language should be included that clearly indicates that R2 and R3 do not have to be completed at the same time ,otherwise this will be left to the interpretation of the auditors. Practically these are not always completed together.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation does not agree with the expanded modeling requirements. While we understand there may be value in developing and providing a model for non-linear protection functions, We don't see the value in developing models for definite-time relay settings rather than just providing those settings. Constellation feels that language should be included that clearly indicates that R2 and R3 do not have to be completed at the same time ,otherwise this will be left to the interpretation of the auditors. Practically these are not always completed together.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Before industry could implement all the protection settings for the models (i.e., R2.3 and R3.3) we would need guidance on proper implementation from industry relay vendors. Better modules within the software should be available to use these settings. As it is today, much work needs to be done with Siemens, GE, and PowerWorld to get these issues addressed before requiring industry to include verification and validation of these settings. The existing software does not readily support these updates for positive sequence dynamic models.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Comments: The obligations related to Requirement R2, subpart 2.3 as it relates to GO and TO modifications to protection systems synchronous generation identified in Section 4.2.1 or 4.2.2 or a synchronous condenser identified in Section 4.2.4.1 should be clarified. Specifically, the SDT should clarify the timeframe that will be required to complete and submit updated models to the TP after protection system changes. EEI requests similar clarifications regarding GO and TO obligations as it relates to Requirement R3, subpart 3.3. Additionally, the Planning Coordinator should be added to these requirements since they share in the development of the planning models.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment	
The obligations related to Requirement R2, subpart 2.3 as it relates to GO and TO modifications to protection systems synchronous generation identified in Section 4.2.1 or 4.2.2 or a synchronous condenser identified in Section 4.2.4.1 should be clarified. Specifically, the SDT should clarify the timeframe that will be required to complete and submit updated models to the TP after protection system changes. EEI requests similar clarifications regarding GO and TO obligations as it relates to Requirement R3, subpart 3.3. Additionally, the Planning Coordinator should be added to these requirements since they share in the development of the planning models.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Derek Brown, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) to question #3.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
Based on the initial requirement Consumers Energy is voting no for this question. We believe that there needs to be a technical attachment added to this requirement clarifying the expectations.	
Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	

Answer	No
Document Name	

Comment

Xcel Energy generally supports the comments of EEI. Below are Xcel Energy comments that indicate additional or differing concerns.

Xcel Energy disagrees with including protective system trips in the standard for Requirements 2.3 and 3.3. Relay settings are static, not dynamic as the Standard title indicates. Relay settings are already included in other PRC Standards and PRC Standards manage those settings. These modifications would require Generator Owners (GO) to perform unnecessary model revisions as relay settings change more frequently and it will create an administrative burden with the number of modeling revisions and significantly increase costs for GOs when protective system changes are made. Specifically, field overcurrent protective systems protect the generator field during collector ring flashover events and have nothing to do with the dynamic response of a generator. This protective system shall not be included in the Standard. Relay settings can be provided to Transmission Planners (TP) via PRC Standard communications and can also be provided in different formats and still achieve the same benefit; without causing GOs to perform unnecessary modeling. In addition, the TP can request protection system settings through MOD-032 data specifications if necessary.

Existing dynamic models for excitation limiters do not adequately represent the behaviors of the various manufacturer equipment. For this reason, limiters are often not modeled. Excitation limiter models should not be required unless adequate generic models are developed. Alternatively, an exemption could be provided if the generic models do not adequately represent the installed equipment. If TPs require data about the limiters, then the data can be requested as part of the data specification in MOD-032.

If limiter models are required by the standard, then clarification is required on the validation requirement of the limiters. It is impractical to provide measured data of the actual limiter response with every validation, particularly if limiter settings remain unchanged. In order to dynamically test the behavior of the limiters, it will be necessary to alter settings in order to activate them within acceptable normal operation limits (voltage, equipment capability curves, etc). The modification of settings while online increases the risk of equipment problems during the test and also increases the likelihood that inadvertent setting changes occur. Performing the modifications while offline increases the burdens imposed by the testing. Because of this, it is unreasonable to require dynamic validation of the limiters, particularly if required with every revalidation.

To correct these concerns, the requirement for excitation limiters and electrical protection should be removed from MOD-026. Data can be requested as part of MOD-032 data specifications if needed by TPs.

Likes 0	
Dislikes 0	

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer	No
Document Name	

Comment

Based on the initial requirement Consumers Energy is voting no for this question. We believe that there needs to be a technical attachment added to this requirement clarifying the expectations.

Likes 0	
Dislikes 0	

Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI and observes that the language of R3 omits reference to the Transmission Owner function.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP does not agree with the inclusion of language pertaining to the models representing Protection Systems of synchronous generating units as stated in R2 and R3, as we believe this to be outside the scope and intention of the Standard Authorization Request "MOD-026-1 Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions, MOD-027-1 Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions" and that of the IRPTF, respectively. The language as stated puts undue burden on the Generator Owners to provide additional protection model data, which may be unnecessary, as well as extremely challenging to execute. As one example, standard model types may be unavailable due to existing limitations of the standard software applications within the utility industry that are needed to perform these analyses. The absence of model types would warrant a significant expenditure of time and resources to comply. Since MOD-032 allows the TP and PC to request protection system data and modeling (if it is believed to be necessary), and since MOD-026-2 is a model verification/validation standard and it is not feasible to validate the modeling of protection functions, this modeling should be left to MOD-032

In addition, the proposed requirements R2 part 2.3 and R3 part 3.3 introduce compliance duplication by requiring the Generator Owner to verify and validate generator protection models whose settings data is already captured through the scope of obligations within a host of active Protection and Control Reliability Standards (e.g. PRC-019, PRC-024, PRC-025, PRC-026, PRC-027, etc.). These standards, when considered in their entirety, serve to meet the concerns expressed by the SDT, as they require that data to be evaluated for in-service equipment, devices, and systems against a wide-range of stipulated criteria designed to address the myriad of scenarios that could negatively impact BES reliability. Therefore, we do not believe the proposed further inclusion of protective function verifications in MOD-026 would result in meaningful contributions to improving the reliability of the BES.

Lastly, for the specific protective functions listed within Requirements R2 part 2.3 and R3 part 3.3, the mechanism to request the desired modeling data by the Transmission Planner/Planning Coordinator already exists via MOD-032. A recommendation would be for those Transmission Planners and/or Planning Coordinators that prefer these modeled protective functions to utilize their existing MOD-032 process to meet that preference and avoid creating inter-reliability standard inefficiencies or duplication and mandating Generator Owners to provide potentially-unnecessary modeling data.

AEP's experience is that the proposed protective function modeling data has not been seen as necessary by Transmission Planners and Planning Coordinators. The rationale for removing the listed protective functions are as follows:

- Stator overcurrent - Not universally applied on synchronous units but if applied, it is likely a limiter or alarm only, not a trip function. If a limiter, it would have an inverse time characteristic likely to extend beyond normal simulation durations. Historically, no requests for this relay protection model have been warranted via MOD-032.
- Field overcurrent – Backup to the over-excitation limiter/maximum excitation limiter (OEL/MXL). It is not necessary to model trip function and has been reinforced through no requests via MOD-032. No model in PSS/E.
- Loss of field - No contingency exists to warrant modeling of the trip function which has been reinforced through no requests for this protection model via MOD-032. Coordinated with the UEL/MEL for out-of-step operation and loss of excitation due to equipment failure which is not a TP studied contingency.
- Out-of-step – Not universally applied on all synchronous units. There are other means to remove unstable units from simulations (there is a check box option in PSS/E, for example). It is not necessary to have this in simulation models which has been reinforced by receiving no requests for this protection model via MOD-032.
- Volts per hertz – Applied to prevent over-excitation of generators/GSUs during start-up and shutdown. Generally a limiter function is coordinated with trip, but in many cases the trip function is active only while the unit is off-line. With exception of UFLS studies, not generally necessary (there are even time-based V/Hz constraints on UFLS program settings in PRC-006 to avoid V/Hz limiter activation); thus, this would not be necessary for modeling as reinforced by receiving no requests for this protection model via MOD-032. No limiter function in PSS/E; trip or monitor only in PSS/E.
- Over/Underspeed – This protective function does not meet the definition of a Protection System as defined within the NERC Glossary of Terms. While this can be synonymous with frequency in an operational context, the NERC definition is explicit in which it refers to "Protective relays which respond to **electrical* quantities". Protective functions which respond to mechanical quantities such as pressure, temperature, etc. are not applicable to the NERC Protection System and should be removed from R3 part 3.3 of the draft standard. This is reinforced via the PRC-005-6 Supplementary Reference which states when defining the Components of Protection Systems…
    - Component of Protection System: Protective relays which respond to electrical quantities
    - Includes: All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.
    - Excludes: Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection Systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System.

Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
Requirements R2 and R3 are almost identical. It is recommended they be grouped into one requirement.	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3

Answer	No
Document Name	

Comment

WEC Energy Group supports EEI and NAGF comments.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA identified that R3.3 is covered under NERC standards PRC-019 and PRC-024. BPA disagrees with including it as part of MOD-026 or MOD-027. BPA believes these revisions are redundant and unnecessary.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We support the subpoints in 2.1, 2.2, 2.3, 3.1, 3.2, and 3.3. However, the generators are able to provide the best available models to the Transmission Planner, but the TP would need to validate the model and provide changes back to the Generator Owner and Transmission Owner.

Likes 0	
Dislikes 0	

Response

Aric Root - CMS Energy - Consumers Energy Company - 4

Answer	No
Document Name	
Comment	
Based on the initial requirement Consumers Energy is voting no for this question. We believe that there needs to be a technical attachment added to this requirement clarifying the expectations.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
As proposed, R2 and R3 each contains a list of information that verified models and accompanying information “shall include at a minimum.” Consider revising that statement to read as follows: “*As applicable*, the verified model(s) and accompanying information shall include, but are not limited to, the following . . . .” This revision would address those instances in which such modeling parameters do not exist. For example, proposed R2.2., R2.3., R3.2. and R3.3. require information related to protection elements. The model components should only be required to include that information if the corresponding device or protection elements exist in the field.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
In the proposed language, we are assuming that R2.2 includes a power factor controller in the description of the outer loop control. If this assumption is incorrect then the language needs to be modified. We suggest adding a footnote stating the outer loop control includes power factor controllers.	
Likes 0	

Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy disagrees with including the proposed Requirements R2.1, R2.2 and R2.3 as minimum modeling requirements. The TP and its PA should jointly determine the required minimum modeling requirements and level of the modeling details as stated in Requirement R1.1. If the TP and PA determine that some or all of these listed minimum requirements are needed for the model or the type of studies performed, they can include such requirements as part of the R1.1. The level of detail and minimum requirements may change based on the type of studies and issues the TP is trying to solve. The model requirements and level of detail for the new facilities may differ for new facilities and some in-service facilities. Therefore, the model(s) level of detail should be left to the TP and PA.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	
The MRO NSRF recommend replacement of “Transmission Planner” with “Transmission Planner and/or Planning Coordinator” in Requirements R1.3., R1.4., and R1.5. For R2.4 “dynamic volt or VAR event” is vague. Language should be changed to “dynamic voltage or reactive power event” to mirror the language in R3.4 (“dynamic active power or frequency event”)	
Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	

Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI for Question #3. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican supports MRO NSRF and EEI 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	

The NAGF has the following concerns and /or comments:

General:

1. PRC-024 requires notification of voltage and frequency trips inside the “no trip zone” to be communicated to the PC/TP.   The PC/TP should use this intelligence to predict unit trip expectations for system voltage and frequency disturbances rather than requiring these elements in the requirements of this standard.

R2.2

a. R2.2 adds excitation limiter models to the information required in MOD-026-1. PCs and TPs should be allowed to determine if they want this information. Many do not currently require such models, so they may be unnecessary.

R2.3

a. R2.3 and R3.3 of MOD-026-2 as presently written appear redundant with MOD-032, which TPs can use to obtain frequency and voltage trip settings. The SDT has advised that they want the settings converted to model form by a modeling specialist, in which case this explanation should be given in the Technical Rationale portion of MOD-026-2. .

b. The addition of the requirement related to limiters and Protection System will require considerable resources (time and money) from generators who will likely need the support of OEMs and / or other 3rd party companies

c. Redundant w/ PRC-019 – recommend putting into PRC-019 revision for consistency and clarity

R2.4

a. Clearly define system disturbance and large system disturbance

b. R2.4 says that all R2.2 models must be validated (i.e. demonstrated through testing or operation), but we often cannot attain the OEL and/or UEL during staged tests for MOD-026 (and MOD-025), due to firstly hitting a limit for generator bus voltage, plant auxiliary system voltages, or the HV system voltage schedule. This impediment cannot be addressed by refining test techniques. When testing a unit that is the mainstay for the local grid for example, we sometimes have to end leading PF tests at a positive MVAR value (i.e. exceptionally far from the UEL), because the grid voltage is taking a nosedive. Testing when the demand on the grid is extremely high (for the OEL) or low (for the UEL) and the excitation limiters could be reached is also not an option. Some ISOs strictly forbid testing under such circumstances. We can’t rely on disturbances or recorded normal-operation data, since most plants almost never reach the OEL or UEL other than when forcing matters in a staged test. The SDT has advised that OEL and UEL models are to only be verified, not validated, but that is not what R2.4 presently says.

R3.1

a. The requirement to state the mode of operation in R3.1 of MOD-026-2 is new and unclear. The SDT has advised that it is meant to indicate frequency-responsive versus running valves-wide-open for steam turbines, but It could be interpreted to mean baseload vs peaking, un-augmented vs duct burners on, Brayton cycle vs Rankine cycle etc. A clarification is needed.

R3.2

a. The expression, “load controller, and other outer loop controls that override the governor response,” should be changed to, “ load controller or other outer loop controls if overriding the governor response.” There’s nothing gained by developing models for ordinary, non-overriding load controls.

R3.3

a. Redundant w/ PRC-019 – recommend putting into PRC-019 revision for consistency and clarity

b. R3.3 is introduced as being limited to Protection Systems, but then includes protection functions related to speed (as distinct from frequency). Overspeed trips that are based on toothed wheel/non-contact pickup instruments are not part of the Protection System, due to responding to a mechanical rather than electrical quantity. If these items are to be included in MOD-026-2 R3.3 should be revised to say so, and the point should be discussed in the Technical Rationale, since this would be a departure from past NERC practice (overspeed trips are not covered under PRC-005 and PRC-024)

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 agrees with the comments provided by EEI for R2, subpart 2.3, adding similar clarification to Requirement R3 subpart 3.3, and the addition of the Planning Coordinator.

In addition to the above EEI comments, PG&E provides the following:

Part 2.4 requires that models for excitation limiters be validated by either a staged test or a measured system disturbance. Measured system disturbance data has minimal application for validating excitation limiters unless the disturbance happens to directly activate the limiter in a meaningful way. Likewise, system limitations, equipment limits, and safe operational practices typically preclude excitation limiters from being validated by staged testing such that meaningful dynamic characteristics may be established for excitation limiter models. Requirement 2.4 should be revised to acknowledge prudent testing/Operational practices and only require validation of the positive sequence dynamic models in Part 2.2 to the extent that safe operating practices and equipment limitations allow.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis

Answer	No
Document Name	

Comment

The SRC is requesting modifications to Requirements R2 and R3 in order to ease in the readability of the Standard Requirements. For example, one must read the sublevels of R2 and R3 to distinguish the purpose. Recommend the following improvements to R2 and R3:

R2 Synchronous Facility Generator Excitation Control System or Plant Volt/Var Control Functions Models and Data Submittals:

For synchronous generation identified in Section 4.2.1 or 4.2.2 or a synchronous condenser identified in Section 4.2.4.1, each Generator Owner or

Transmission Owner shall provide a verified positive sequence dynamic model(s), associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s) and accompanying information shall include at a minimum the following:

R3 Synchronous Facility Turbine/Governor and Load Control or Active Power/Frequency Control Functions Model & Data Submittals:

For synchronous generation identified in Section 4.2.1 or 4.2.2, each Generator Owner shall provide a verified positive sequence dynamic model(s), associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following:

The main goal for power system transient study is to study angle stability and power system oscillation. The simulation normally covers up to 20 seconds post fault situation. Most excitation

limiters and outer-loop controls will have little or no impacts. Having every owner provide this information is burdensome. The standard should focus on requiring excitation limiter and outer-loop controls only on an as needed bases.

For voltage relays, during the simulation, we could normally assume that the units meet the requirements in NERC standard PRC-024-2. So, as long as, the power system transient stays inside 'OFF NOMINAL FREQUENCY CAPABILITY CURVE' and 'Voltage Ride-Through Time Duration Curve', the units should not trip. As a result, the voltage relays should not be included in MOD-026-2 documents as they are duplicative to PRC-006 or PRC-024.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer	No
Document Name	

Comment

Eversource suggests that the 20MVA threshold identified in Applicability section 4.2.4 should be inclusive of multiple units aggregated to 20 MVA at a station (substation, switching station, generating station). Some locations may have multiple smaller (example 15MVA) reactive resources of the types mentioned in R4.2.4.1 in order to meet reliability criteria which can consider the contingent loss of one or a number of the resources. The impact of multiple units (example 2 units of 15MVA each) on the results of analysis can be more notable than a single 20MVA resource.

Likes 0	
Dislikes 0	

Response

Glenn Pressler - CPS Energy - 3

Answer	No
Document Name	

Comment

No. CPS Energy supports the comments from Duke, AECI, Xcel, and others.

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; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ

Answer	No
Document Name	
Comment	
Extend prior Q1 response. In addition, provisions 2.3 and 3.3 are duplicative of PRC-019 requirements. Verification does not explicitly require a match to the as-built installation, only generic model conformance.	
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	

For R2.4 “dynamic volt or VAR event” is vague. Language should be changed to “dynamic voltage or reactive power event” to mirror the language in R3.4 (“dynamic active power or frequency event”)

Southern Company believes that an annual evaluation of the most recent 3-year capacity factor for every unit is excessive. Whereas the periodic re-evaluation of the model sufficiency is deemed to be adequate on a 10-year repeat basis, so should be the capacity factor exemption criteria.

PRC-024 requires notification of voltage and frequency trips inside the “no trip zone” to be communicated to the PC/TP. The PC/TP should use this intelligence to predict unit trip expectations for system voltage and frequency disturbances rather than requiring these elements in the requirements of this standard.

Southern Company agrees that the exclusion provided in Attachment 1, Row 11 is necessary. However, we propose that the first element of the three-part OR statement be changed from “Commissioning date of the Facility is before January 1, 2015;” to “Commissioning date of the Facility is before the effective date of MOD-026-2;” so that equipment owners will have the opportunity to specify that an EMT model be supplied with the equipment purchased.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	

Comment

We suggest that R2.2 and R2.3 / R3.2 and R3.3 be set up such that GOs and/or TOs are only providing those specific models that the PC/TP requires (and we feel that models that are required should be from MOD-032). Providing a quasi-detailed list here in the standard means standard language changes when best practices change, and will have issues with comprehension. For example, some GOs may not understand what “outer loop controls that override the governor response” means (and how to generate a concrete, complete list for themselves from this language), nor will they understand what we mean by “mode of operation” in R3.1– that should be a list of choices for the GO to pick from. Similarly, language in R2.3 and 3.3 could confuse whether we are adding plant DCS controls to standard applicability. We need to be more explicit about what “directly trip the turbine generator” really means in practice – with modern digital controls that is not as straight forward as you would think. We suggest using language like “trip the generator and/or field breakers directly or through lockout or auxiliary relays” or something to that effect.

Likes 0	
Dislikes 0	

Response

James Howell - Southern Company - Southern Company Generation - 5

Answer	No
Document Name	

Comment

See Southern Company Comments

Likes 0	
Dislikes 0	

Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

R1 requires the Transmission Planner and its Planning Authority (Coordinator) to “develop dynamic model requirements and processes” and to make them “available to the Generator Owner and Transmission Owner”. R2 and R3 then set specific minimum requirements for “verified model(s) and accompanying information” to be provided to the Transmission Planner. The standard should focus on verifiable modeling data that are necessary for performing simulations and avoid requirements for superfluous information. The standard should not set “at a minimum” expectations in R2 and R3 while requiring the TP/PC to establish their dynamic modeling data needs in R1, potentially creating a conflict.

R2, Part 2.3 and R3, Part 3.3 require that “model(s) representing enabled Protection Systems that directly trip…” the equipment of interest be provided. Does this mean that dynamic modeling data to be provided for the equipment of interest in R2, Part 2.2 and R3, Part 3.2 should factor in Protection System settings that will influence performance of the equipment during dynamic events as part of the model data verification process? If so, it might be difficult to demonstrate compliance with R2, Part 2.3 and R3, Part 3.3 as written. The intent could be rolled into the preceding sub-part or the wording modified for clarity.

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	No
Document Name	
Comment	

SPP has a concern that Requirements R2 and R3 only has the interest of the Transmission Planner (TP) in mind when gathering pertinent data to conduct their analysis. The Technical Rationale states “The Transmission Planner (TP) must be able to study this behavior to assess and mitigate the reliability risk. Elements of concern include voltage, V/Hz, loss of field, stator/field overcurrent, as they are recognized as potentially sensitive to large disturbance events and are operating on quantities of direct regulation by the excitation system”. From our perspective, the Planning Coordinator (PC) should have access to the TP analysis data (final results) to ensure they can identify the same risks as the TP in reference to the reliability of the grid.

SPP suggests that the drafting team create language in the standard that would require that the TP to share their analysis (final) results with the PC (proposed language shown below).

“Once the TP has completed their analysis, they are to coordinate and/or share the final analysis results with the PC so, they can review models and provide feedback to the applicable situation.”

Additionally, SPP suggests that Requirements R2 and R3 contain language that requires the GOs and TOs should provide verified generator and synchronous condenser EMT models to the PC in addition to positive sequence dynamic models. These models shall be according to RTO model requirements.

Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	

R2 and R3 in particular also appear to have new material beyond the scope of changes presented in the SARs for the MOD-026/27 standard revision. In particular, protection system items found in the new proposed MOD-026-2 R2.1, R2.3, R3.1, and R3.3. all appear to add new requirements not found in the current standards or in the SARs.

While information on protection systems is indeed useful to Transmission Planners, such additions should follow the NERC process. Furthermore, this would appear to interfere with provisions in MOD-032 which allow for requesting of such data. Additionally, not all generators have these types of listed (required) protection to model; lastly, the requirement is a general statement “Model(s) representing enabled Protection Systems that directly trip…”. However, under R3/R4 of the proposed standard, these generator response models are clearly intended to be positive sequence models. Thus, relay models for such things as ground protection, negative sequence, phase imbalance, etc. are clearly unsuitable for modeling in a positive sequence model environment; therefore, the SDT should consider revising this to limit the relay modeling scope to only those relays that are appropriate for the positive sequence environment, and that are supported by the Transmission Planner’s study software. Such generator protections can also exist on the generator step-up transformer or generator tie line, further (and unsuitably) expanding the scope of the new proposed protection system modeling requirements.

Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	

Agree with comments submitted by BPA.

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	

Comment

Comments: R2.3 is unclear. The Protection Systems that directly trip the generator/synchronous condenser include typically protection functions that use positive, negative or zero sequence quantities. While it might be implied that protection functions based on positive sequence quantities should be modelled, since the planning/ operating tools are typically using positive sequence models, the current wording can be confusing.

Some of the Out of Step protection function implementations can't be simulated in the current planning/operating tools.

Modelling of field current limiters is very challenging from accuracy perspective for example for rotating type exciters.

R3.3 is unclear. The Protection Systems that directly trip the turbine-generator include typically protection functions that use positive, negative or zero sequence quantities. While it might be implied that protection functions based on positive sequence quantities should be modelled, since the planning/ operating tools are typically using positive sequence models, the current wording can be confusing.

When renewable energy resources (wind or solar farms) are aggregated in equivalent planning/operating feeder/generator models, the accuracy required by protection functions installed at turbine/inverter /feeder level might be difficult to achieve, leading to simulated erroneous protection actions/non-actions.

R2.3 and R3.3 should consider that the planning/operating tools based on positive sequence models have limited capabilities in properly simulating the Protection Systems performance.

The following standards: PRC 019, PRC-024 (currently under substantial revision), PRC-025 and PRC-026 are meant to ensure that the applicable BES facilities are not inadvertently tripped under various planning/operating conditions.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	Yes
Document Name	

Comment

No Comments

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	
Comment	

WECC agress wtih and supports the language and purpose of R2 and R3. However, since the initial language of R2 and R3 are extremely similar, and it is not until Parts 2.2 (R2) and 3.2 (R3) that what is being asked for is identified, it may make the Requirements clearer and not initially interpreted as the same requirement if the following clarifying language was added before the existing language in the proposed requirements:

R2: For ***Excitation System Modeling***, synchronours generation...

R3: For ***Turbine/Governor Modeling***, synchrounous generation...

Bold text identifies potential clarifying language.

Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6

Answer	Yes
Document Name	
Comment	

Black Hills Corporation supports EEI’s comments with the clarification of obligations to R2 subpart 2.3, Sections 4.2.1, 4.2.2 and 4.2.4.1. In addition to Transmission Planner, Planning Coordinator needs to be added to the requirements language.

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	

How will be the protections modeled in PSS/E software? Will NERC provide guidance on this topic?

Likes 0	
Dislikes 0	

Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
See suggested changes from Question 2 on Requirement R1.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
See suggested changes from Question 2 on Requirement R1.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Dwanique Spiller, Berkshire Hathaway - NV Energy, 5; - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Pam Syrjala, Salt River Project, 5, 3, 1, 6; Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez	
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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

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

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
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	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE requests clarification on the term “turbine-generator” in Requirement Part 3.3.	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	

National Grid supports EEI's comments.
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
The ITC Standards Under Development Team has received no response to submit from the Standard Owners
Likes 0
Dislikes 0
Response

4. Do you agree the language proposed in MOD-026-2 Requirements R4 and R5? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Glenn Pressler - CPS Energy - 3	
Answer	No
Document Name	
Comment	
No. CPS Energy supports EEI and other's comments.	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
Eversource suggests that the 20MVA threshold identified in Applicability section 4.2.4 should be inclusive of multiple units aggregated to 20 MVA at a station (substation, switching station, generating station). Some locations may have multiple smaller (example 15MVA) reactive resources of the types mentioned in R4.2.4.2 in order to meet reliability criteria which can consider the contingent loss of one or a number of the resources. The impact of multiple units (example 2 units of 15MVA each) on the results of analysis can be more notable than a single 20MVA resource.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	No
Document Name	
Comment	

The SRC recommends the following (as provided in our response to Question 3), we recommend adding clarifying titles to the sections:

R4 Inverter Based Resource Excitation Control System or Plant Volt/Var Control Functions Model and Data Submittals:

For inverter based resources (IBRs) identified in Section 4.2.3, FACTS devices identified in Section 4.2.4.2, and VSC HVDC identified in section 4.2.5.2, each Generator Owner or Transmission Owner shall provide a verified positive sequence dynamic model(s), associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following:

R5 Inverter Based Resource Load Control or Active Power/Frequency Control Functions Model & Data Submittals For inverter based resources (IBRs) identified in Section 4.2.3, LCC HVDC identified in Section 4.2.5.1, and VSC HVDC identified in Section 4.2.5.2, each Generator Owner or Transmission Owner shall provide a verified positive sequence dynamic model(s), associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)shall include at a minimum the following:

For frequency protection, during the simulation, the TP could normally assume that the units meet the requirements in NERC standard PRC-024-2. So, as long as, the power system transient stays inside ‘OFF NOMINAL FREQUENCY CAPABILITY CURVE’ the units should not trip. If the TP is to try to study extreme system conditions, maybe the TP could collect the relay information based on the special study requirement. So, we believe the frequency relays should not be included in MOD-026-2 documents as they are duplicative to PRC-006 or PRC-024.

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 agrees with the comments provided by EEI on clarifications and the addition of the Planning Coordinator.

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 has the following concerns and /or comments:

General:

1. Replace “Transmission Planner” with “Transmission Planner and / or Planning Authority”

2. Contain duplicative / over lapping requirements which need to be corrected 3. IBR resources should not be required to provide both positive sequence models and EMT models as specified in R4, R5, and R6. The TP/PC should be the entity that chooses the particular modeling needed for their system studies	
Likes 0	
Dislikes 0	
Response	
Durga Gautam - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The intent of requiring software/firmware version number in the context of positive sequence dynamic model isn't clear in Requirements R4 and R5. The models are developed to capture product features relevant to assessing performance of the IBR when connected to the bulk power system and aren't intended to capture all functionalities in the product. Clarification on this be provided in MOD as it is not reasonable to reflect every change to IBR and plant firmware in the model.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican supports MRO NSRF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	

Comment	
Exelon concurs with the comments submitted by the EEI for Question #4. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	

George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
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 Regional Standards Committee	
Answer	No
Document Name	
Comment	
NPCC RSC suggests that the 20MVA threshold identified in Applicability section 4.2.4 should be inclusive of multiple units aggregated to 20 MVA at a station (substation, switching station, generating station). Some locations may have multiple smaller (for example 15MVA) reactive resources of the types mentioned in R4.2.4.2 in order to meet reliability criteria which can consider the contingent loss of one or a number of the resources. The impact of multiple units (for example 2 units of 15MVA each) on the results of the analysis can be more notable than a single 20MVA resource.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO	
Answer	No

Document Name	
Comment	

We recommend replacement of “Transmission Planner” with “Transmission Planner and/or Planning Coordinator” in Requirements R4. and R5.

The MRO NSRF notes requirements R4 and R5 could be duplicative and have overlapping requirements. It suggests the SDT review R4 and R5 to eliminate duplication where possible.

Better NERC BES Unit Definition:

While the MRO NSRF agrees that it’s necessary to model inverter based resources, it recommends better NERC BES “unit” and NERC BES “plant” definitions. Several existing and developing NERC processes (NERC GADS, EOP-012-1, and MOD-026-2) reference generating unit or generating units. The term unit is ambiguous by itself and could be either an individual generating resource or an aggregated group of like units.

• The MRO NSRF suggests, defining NERC BES “unit” as an individual NERC BES generating resource. NERC BES “plant” should be “an aggregate group of similar or like individual generating resources”.

• The MRO NSRF suggests the SDT also consider hybrid collocated units should be addressed. It’s the MRO NSRF’s experience synchronous, IBR, and hybrid plants are different enough that they need their own consideration.

Alternately,

The SDT could improve the 4.2.3 definition. I4 references each “individual generating resource” which isn’t feasible in model building. The MRO NSRF recommends 4.2.3 be modified to:

4.2.3 Generating plant or Facility of equivalent NERC BES aggregate generators, meaning groups of like individual generator resources for Facilities identified in I4 that all aggregate to more than 75 MVA at a common point of interconnection.

The reliability objective is not to model individual I4 generating resources, rather to model groups of like individual generating resources. Modeling groups of equivalent resources is already a common practice for models and GADS reporting.

Wind or solar farms can consist of 100 – 300 (or more) of individual inverter / converter combinations. Care needs to be taken to allow combined and aggregate models of like individual units.

Large System Disturbance Definition:

The MRO NSRF suggests, the SDT better define what is a large system disturbance. The MRO NSRF suggests defining large system disturbance by moving Attachment 1, Note 1 to the top in Section 6 and adding an equivalent voltage criteria. See the technical rationale, section R4 where it’s stated R4 is specific to positive sequence modeling and reflects the intent of the SAR to verify both small signal performance via staged testing (termed as validation).

The MRO suggests adding technical rationale language clarifying that large signal performance validation or verification could be completed via simulations.

Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy supports the comments as submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
In the proposed language, we are assuming that R4.2 includes a Power Factor Controller in the description of the outer loop control. If this assumption is incorrect then the language needs to be modified. We suggest adding a footnote stating the outer loop control includes power factor controllers.	
Likes 0	
Dislikes 0	
Response	

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
As proposed, R4 and R5, each contains a list of information that verified models and accompanying information “shall include at a minimum.” Consider revising that statement to read as follows: “*As applicable*, the verified model(s) and accompanying information shall include, but are not limited to, the following . . . .” This revision would address those instances in which such modeling parameters do not exist. For example, proposed R4.2., R4.3., R5.2. and R5.3. require information related to protection elements. The model components should only be required to include that information if the corresponding device or protection elements exist in the field.	
Likes 0	

Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Will TP be using all of data supplied? R4.3, R4.4, R5.3, and R5.4 are already covered in MOD-032.	
Likes 0	
Dislikes 0	
Response	
Aric Root - CMS Energy - Consumers Energy Company - 4	
Answer	No
Document Name	
Comment	
The approved models need more development and there will still need to be a technical attachment clarifying the expectations.	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
We support the subpoints in 4.1, 4.2, 4.3, 5.1, 5.2, and 5.3. However, the generators are able to provide the best available models to the Transmission Planner, but the TP would need to validate the model and provide changes back to the Generator Owner and Transmission Owner.	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1	
Answer	No
Document Name	
Comment	
Are modeling requirements in Requirement R4 applicable to double-fed induction generators (DFIG)? In addition, National Grid supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
R5 – BPA uses standard HVDC models available in grid simulation packages like Siemens PSS/E, GE PSLF or PowerWorld. The model data must match model structure that is implemented in the industry used grid simulators.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	No
Document Name	
Comment	
WEC Energy Group supports EEI and NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
Requirements R4 and R5 are almost identical. It is recommended they be grouped into one requirement.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	No
Document Name	
Comment	
The approved models need more development and there will still need to be a technical attachment clarifying the expectations.	
Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	

Answer	No
Document Name	
Comment	

Xcel Energy generally supports the comments of EEI. Below are Xcel Energy comments that indicate additional or differing concerns.

As in response to Question 3 of this comment form, Xcel Energy also disagrees with including protective system trips in the Standard for Requirements 4.3 and 5.3. Xcel Energy maintains that relay settings are static, not dynamic as the Standard title indicates. Relay settings are already included in other PRC Standards and PRC Standards manage those settings. As indicated in Question 3, these modifications would require Generator Owners (GO) to perform unnecessary model revisions as relay settings change more frequently and it will create an administrative burden with the number of modeling revisions and significantly increase costs for GOs when protective system changes are made. Relay settings can be provided to Transmission Planners (TP) via PRC Standard communications and can also be provided in different formats and still achieve the same benefit; without causing GOs to perform unnecessary modeling. In addition, the TP can request protection system settings through MOD-032 data specifications if necessary.

Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	No
Document Name	
Comment	

The approved models need more development and there will still need to be a technical attachment clarifying the expectations.

Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Derek Brown, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster

Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) to question #4.

Likes 0	

Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The obligations related to Requirement R4, subpart 4.3 as it relates to GO and TO modifications to protections for inverter based resources (IBRs) identified in Section 4.2.3, FACTS devices identified in Section 4.2.4.2, and VSC HVDC identified in section 4.2.5.2 should be clarified. Specifically, the SDT should clarify the timeframe that will be required to complete and submit updated models to the TP after protection changes. EEI requests similar clarifications regarding GO and TO obligations as it relates to Requirement R5, subpart 5.3. Additionally, the Planning Coordinator should be added to these requirements since they share in the development of the planning models.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Comments: The obligations related to Requirement R4, subpart 4.3 as it relates to GO and TO modifications to protections for inverter based resources (IBRs) identified in Section 4.2.3, FACTS devices identified in Section 4.2.4.2, and VSC HVDC identified in section 4.2.5.2 should be clarified. Specifically, the SDT should clarify the timeframe that will be required to complete and submit updated models to the TP after protection changes. EEI requests similar clarifications regarding GO and TO obligations as it relates to Requirement R5, subpart 5.3. Additionally, the Planning Coordinator should be added to these requirements since they share in the development of the planning models.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No

Document Name	
Comment	

Clarification is needed on the implementation period for existing IBR devices that were not part of the scope of MOD-026 or MOD-027 before this change (i.e., Transmission Owner devices), but which are now going to be applicable to R4 and R5.

We also believe that clarification needs to be made that models for aggregations of plants with similar inverters need to be taken into account rather than modeling all individual inverters.

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6

Answer	No
Document Name	
Comment	

Constellation feels that language should be included that clearly indicates that R4, R5, and R6 do not have to be completed at the same time, otherwise this will be left to the interpretation of the auditors. Practically these are not always completed together.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Alison Mackellar - Constellation - 5

Answer	No
Document Name	
Comment	

Constellation feels that language should be included that clearly indicates that R4, R5, and R6 do not have to be completed at the same time ,otherwise this will be left to the interpretation of the auditors. Practically these are not always completed together.

Kimberly Turco 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 agrees with EEI's comments: The obligations related to Requirement R4, subpart 4.3 as it relates to GO and TO modifications to protections for inverter based resources (IBRs) identified in Section 4.2.3, FACTS devices identified in Section 4.2.4.2, and VSC HVDC identified in section 4.2.5.2 should be clarified. Specifically, the SDT should clarify the timeframe that will be required to complete and submit updated models to the TP after protection changes. EEI requests similar clarifications regarding GO and TO obligations as it relates to Requirement R5, subpart 5.3. Additionally, the Planning Coordinator should be added to these requirements since they share in the development of the planning models.	
Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
See observations for Requirment 6 noted below for Question #5.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FE agrees with EEI's comments:

The obligations related to Requirement R4, subpart 4.3 as it relates to GO and TO modifications to protections for inverter based resources (IBRs) identified in Section 4.2.3, FACTS devices identified in Section 4.2.4.2, and VSC HVDC identified in section 4.2.5.2 should be clarified. Specifically, the SDT should clarify the timeframe that will be required to complete and submit updated models to the TP after protection changes.

EEI requests similar clarifications regarding GO and TO obligations as it relates to Requirement R5, subpart 5.3.

Additionally, the Planning Coordinator should be added to these requirements since they share in the development of the planning models.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Suggest the following actions:

1. Create a seperate standard for IBRs.
2. Remove requirement to provide software/firmware version numbers to transmission planners.
3. Remove the requirement to supply protection models.
4. Make PRC-019 and PRC-024 documents available to TPs so they can populate models as needed.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Similar to the response of Question 3, the addition of limiters and Protection System settings are not justified.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	

Manitoba Hydro does not agree with including 4.1, 4.2, and 4.3 as minimum modeling requirements. We think that it is up to the TP / PA to determine the required minimum modeling requirements and level of the modeling details as stated in R1 (1.1). If the TP / PA determines that some or all these listed minimum requirements are needed to include in the model base or the type of performed studies they can include these as part of the R1 (1.1, level of detail).

The R4 part 2.3 should be limited to the applicable protection and limiting functions models when requested by the Planning Authority and the Transmission Planner. Some of these models stated in 4.2 and 4.3 may not be available in the standard library of the required simulation tools (developing user's defined models) and they may not add any additional benefit to the modeling accuracy and validation process. Also, it could be very hard to validate the accuracy of these models. No point in adding more information to the models if it is not possible to test them with a reasonably overhead cost.

Alternately,

We recommend replacing 4.1, 4.2, and 4.3 with the following:

3.1 The verified model(s) and accompanying information shall include the minimum model requirements and level of detail as stated in R1 part 1.1 and part 1.3 by their TP / PA.

Or

The verified model(s) and accompanying information shall include the minimum model requirements as stated by their TP / PA in R1 part 1.1 and part 1.3 which may include the following

4.1. Manufacturer, model number, and software/firmware version number of the IBR unit (s)3 and power plant controller;

4.2. Model(s) representing the IBR unit(s), and associated reactive power control system4 including the IBR unit's electrical control, power plant controller, auxiliary reactive resources, and other equipment which impacts plant voltage and reactive power dynamic response;

4.3. Model(s) representing enabled protections5 and limiting functions,6 that either directly trip IBR unit(s) or plant, or limit active/reactive output of the IBR unit or plant; and

Regarding R5: Same as the above comments.

Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	

Comment	
Similar to the response of Question 3, the addition of limiters and Protection System settings are not justified.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
The obligations related to Requirement R4, subpart 4.3 as it relates to GO and TO modifications to protections for inverter based resources (IBRs) identified in Section 4.2.3, FACTS devices identified in Section 4.2.4.2, and VSC HVDC identified in section 4.2.5.2 should be clarified. Specifically, the SDT should clarify the timeframe that will be required to complete and submit updated models to the TP after protection changes. EEI requests similar clarifications regarding GO and TO obligations as it relates to Requirement R5, subpart 5.3. Additionally, the Planning Coordinator should be added to these requirements since they share in the development of the planning models.	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	
Same logic as my comments for R2 and R3. Protection System coordination should remain under PRC-019. Any new TP reporting R4.3 and R5.3) should be added to PRC-019.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	

Answer	No
Document Name	
Comment	

Agree with comments submitted by BPA.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

R1 requires the Transmission Planner and its Planning Authority (Coordinator) to “develop dynamic model requirements and processes” and to make them “available to the Generator Owner and Transmission Owner”. R4 and R5 then set specific minimum requirements for “verified model(s) and accompanying information” to be provided to the Transmission Planner. The standard should focus on verifiable modeling data that are necessary for performing simulations and avoid requirements for superfluous information. The standard should not set “at a minimum” expectations in R4 and R5 while requiring the TP/PC to establish their dynamic modeling data needs in R1, potentially creating a conflict.

R4, Part 4.3 and R5, Part 5.3 require that “model(s) representing enabled protections and limiting functions…” that directly trip or limit the equipment of interest be provided. Does this mean that dynamic modeling data to be provided for the equipment of interest in R4, Part 4.2 and R5, Part 5.2 should factor in Protection System settings that will influence performance of the equipment during dynamic events as part of the model data verification process? If so, it might be difficult to demonstrate compliance with R4, Part 4.3 and R5, Part 5.3 as written. The intent could be rolled into the preceding sub-part or the wording modified for clarity.

Likes 0	
Dislikes 0	

Response

James Howell - Southern Company - Southern Company Generation - 5

Answer	No
Document Name	

Comment

See Southern Company Comments

Likes 0	

Dislikes 0	
Response	

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	
Comment	

Consistent with our other comments, we believe specifics on what plant equipment and characteristics should be modeled belongs 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	

Southern Company believes that Requirements R4 and R5 contain duplicative, overlapping requirements. The duplication needs to be eliminated.

To create a distinction between generating units vs generating plants, we recommend 4.2.3 be modified to:

4.2.3 Generating plant or Facility of equivalent NERC BES aggregate generators, meaning groups of like individual generator resources for Facilities identified in I4 that all aggregate to more than 75 MVA at a common point of interconnection.

since the reliability objective is not to model individual I4 generating resources, but rather to model groups of like individual generating resources. Modeling groups of equivalent resources is already a common practice for models and GADS reporting. Wind or solar farms can consist of 100 – 300 (or more) of individual inverter / converter combinations. Care needs to be taken to allow combined and aggregate models of like individual units.

Large System Disturbance Definition: We suggest that the SDT better define a large system disturbance. defining large system disturbance by modifying Attachment 1, Note 1 to specify a voltage criterion that represents a large system disturbance.

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; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	No
Document Name	
Comment	
R4 provision 4.2 subnote 4 should be expanded to explicitly include Phase Locked Loop (PLL) controls, as implicated in the Odessa IBR tripping event root cause investigation. R5 provision 5.4 excludes a time duration, negating the ability to demonstrate "ride through" as contemplated in the draft update for IBRs in PRC-024.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
See suggested changes from Question 2 on Requirement R1.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
WECC agress wtih and supports the language and purpose of R4 and R5. Similar to the comment for Question 3, WECC suggests the addition of a few clarifying words prior to the existing language in the proposed Requirements R4: For ***voltage modeling***, inverter bases resources...	

R5: For ***frequency modeling***, inverter based resources...

Bold text identifies potential clarifying language.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	Yes
Document Name	

Comment

No Comments

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	Yes
Document Name	

Comment

SPP has a concern with the rationale for Requirement R4; which states, “This requirement has both verification and validation activities including documentation of manufacture and equipment information, modeling of hardware and control systems, requirement for validation (staged testing or disturbance monitoring), and protection system modeling.”

SPP has found it difficult to obtain the above referenced data from manufacucting entities due to proprietary interests. These requirements should give the TP and PC the flexibility to gain access to pertinent modeling data to ensure the building of accurate models.

SPP suggests the MOD-026 drafting team coordinate with the MOD-032 drafting team to ensure the appropriate data collection is addressed to help meet the industry’s needs pertaining to the verification and validation activities for positive sequence models.

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	Yes
Document Name	
Comment	
See suggested changes from Question 2 on Requirement R1.	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Dillard - Austin Energy - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 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	
Israel Perez - Israel Perez On Behalf of: Pam Syrjala, Salt River Project, 5, 3, 1, 6; Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Dwanique Spiller, Berkshire Hathaway - NV Energy, 5; - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 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	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
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

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Black Hills Corporation supports EEI comment.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE agrees with the SDT's approach to include inverter-based resources. Texas RE recommends defining the term IBR unit(s) in the NERC Glossary of terms rather than describing it in a footnote of a single requirement (Requirement Part 4.1). It seems as though this term could be used in additional future requirements and it would be more clear to have a NERC Glossary definition. Texas RE seeks clarification on the difference in the terms "IBR unit(s)" and "plant" as used in Requirement Parts 4.3 and 6.3. The addition of "or plant" appears in some parts, but not others. Texas RE noticed Requirement R5.1 says "IBR unit(s), power plant controller," while Requirement 4.1 said IBR unit(s) and power plant controller.	
Likes 0	
Dislikes 0	
Response	

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	
Document Name	
Comment	
N/A R4 and R5 are only for inverter based resources.	

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	
The ITC Standards Under Development Team has received no response to submit from the Standard Owners	
Likes 0	
Dislikes 0	
Response	

5. Do you agree the language proposed in MOD-026-2 Requirement R6? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	

EEI does not agree that EMT models are needed everywhere at this time. We also do not agree that the industry is sufficiently prepared to develop large scale EMT models at this time. Instead, these models should be limited to those areas where the needs are most urgent and as directed by the responsible Transmission Planner (TP), in cooperation with the responsible Planning Coordinator (PC). For this reason, criteria should be developed by the SDT to help guide the industry when EMT models are needed. This will ensure that lessons learned can be developed and applied over time as these models become necessary. We recommend the following edits to Requirement R6:

R6: **After a formal analysis by the Transmission Planner (TP) and as a result of their inability to conduct accurate dynamic simulations that reflect and assess BES reliability performance that due to the growth of IBRs (or in cases where IBRs are being installed in areas with low short circuit strength) the TP shall submit data requests to affected GOs and TOs to For applicable units of inverter based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2, each Generator Owner or Transmission Owner shall** provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the **effected** Facilit**ies** to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following:

Requirement R6, subpart 6.2 and the use of the term "large signal disturbances" should be clarified. Currently, small signal disturbances are tested and verified by injecting a small step change (e.g., a 2.5% step change) into excitation and frequency response controls. A large disturbance potentially means something that would be outside of a control system or units deadband. EEI does not agree that entities should be required to inject large signal disturbances which could damage equipment or cause a system disturbance for a mandatory test. For this reason, clarity regarding what was intended by this language should be provided.

Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	

The use of EMT models has not been effectively demonstrated as necessary in addition to the use of positive sequence models in the context of stability/planning. The limited applicability of EMT models to isolated locations does not justify their inclusion into the standard.

Likes 0	

Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	

Comment

Manitoba Hydro recommends that this requirement should be limited only to newly interconnecting inverter-based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2 to the BPS and to upon request of any of these applicable in-service devices by the TP / PA. EMT models are complex and it will take long time to train personnel and develop EMT models.

Manitoba Hydro does not agree with including 6.1, 6.2, and 6.3 as minimum modeling requirements. We think that it is up to the TP / PA to determine the required minimum modeling requirements and level of the modeling details as stated in R1 (1.2). If the TP / PA determines that some or all these listed minimum requirements are needed to include in the model base or the type of performed studies they can include these as part of the R1 (1.2, level of detail). The level of detail and minimum requirements may change based on the type of studies and studies issues. The model requirements for the new facilities may differ from the in-service facilities and some in-service facilities may require a different level of detail. Therefore, the model(s) level of detail should be left to the TP / PA.

Alternately,

We recommend replacing 6.1, 6.2, and 6.3 with the following:

3.1 The verified model(s) and accompanying information shall include the minimum model requirements and level of detail as stated in R1 part 1.2 and part 1.3 by their TP / PA.

Or

The verified model(s) and accompanying information shall include the minimum model requirements as stated by their TP / PA in R1 part 1.2 and part 1.3 which may include the following:

6.1. Attestation from respective original equipment manufacturer(s) (OEM) stating the IBR unit model(s), power plant controller model, and auxiliary control devices model(s) represent the equipment supplied by the OEM.8 If an attestation from an OEM is not obtainable, the Generator Owner or Transmission Owner shall document the reason;

6.2. Device test9 results demonstrating a comparison of the IBR unit's response and the IBR unit's EMT model response for large signal disturbances. If device test results are not obtainable, the Generator Owner or Transmission Owner shall document the reason;

6.3. Facility EMT model and associated parameters representing the IBR unit(s), collector system, auxiliary devices, power plant controller, main transformer(s), and enabled protections and controls that either directly trip IBR unit(s) or plant, or limit active/reactive output of the IBR unit or plant;10

Regarding the 6.5 requirement: this requirement should be removed. Manitoba Hydro does not think that comparing the response of positive sequence dynamic model(s) of Requirement R4 and R5 to the response of Facility EMT model of Requirement R6 for large signal disturbances will add any tangible benefit to the model validation process. These two models required different levels of detail model representation and simulation time steps. What are the validation criteria?

Likes 0	
Dislikes 0	

Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	

The use of EMT models has not been effectively demonstrated as necessary in addition to the use of positive sequence models in the context of stability/planning. The limited applicability of EMT models to isolated locations does not justify their inclusion into the standard.

Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Transmission planners can't study the entire system with EMT models and should only be required if Transmission provides justification for them on a case-by-case basis. Technical Justification should include conditions needed to study (e.g., insulation coordination, switching surge, SSR, TRV, higher-frequency control interactions, series capacitor design studies, etc.). If positive sequence models are properly validated/verified, the system can be accurately studied. Providing EMT models will put a significant financial burden on generator owners with minute benefit to the system.

Suggestions:

1. Revise this section to only be required if justification is provided from TP.
2. Remove 6.1. This requirement requests excessive oversight by transmission and implies GOs are not capable of ensuring models are properly documented and expands audit scope. The risk of non-compliance outweighs the reliability benefits. Not all facilities use a single supplier for all systems. Requiring attestation from OEM is implying GOs are not capable of supplying the correct data.
3. Remove 6.5. Comparisons of EMT and Positive Sequence Models may have slight differences and comparing the response becomes a point for TP to dispute.
4. Create a separate standard for IBRs.
5. It will take considerable time for the industry to become knowledgeable on IBRs with EMT models so a 5-year implementation period is suggested.

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	

Answer	No
Document Name	
Comment	

FE agrees with EEI's comments:

EEI does not agree that EMT models are needed everywhere at this time. We also do not agree that the industry is sufficiently prepared to develop large scale EMT models at this time. Instead, these models should be limited to those areas where the needs are most urgent and as directed by the responsible Transmission Planner (TP), in cooperation with the responsible Planning Coordinator (PC). For this reason, criteria should be developed by the SDT to help guide the industry when EMT models are needed. This will ensure that lessons learned can be developed and applied over time as these models become necessary. We recommend the following edits to Requirement R6:

R6: **After a formal analysis by the Transmission Planner (TP) and as a result of their inability to conduct accurate dynamic simulations that reflect and assess BES reliability performance that due to the growth of IBRs (or in cases where IBRs are being installed in areas with low short circuit strength) the TP shall submit data requests to affected GOs and TOs to** provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the **effected** Facilit**ies** to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following:

Requirement R6, subpart 6.2 and the use of the term "large signal disturbances" should be clarified. Currently, small signal disturbances are tested and verified by injecting a small step change (e.g., a 2.5% step change) into excitation and frequency response controls. A large disturbance potentially means something that would be outside of a control system or units deadband. EEI does not agree that entities should be required to inject large signal disturbances which could damage equipment or cause a system disturbance for a mandatory test. For this reason, clarity regarding what was intended by this language should be provided.

Likes 0	
Dislikes 0	
Response	

Isidoro Behar - Long Island Power Authority - 1

Answer	No
Document Name	
Comment	

Requirement 6 is for applicable units of inverter based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2.

Sub requirements R6.1, 6.2 and 6.3 specifically mention "IBR units". Using this term may be confusing. It is recommended to change the term "IBR units" within 6.1, 6.2 nd 6.3 to encompass all applicable faciltiies itemized at the beginning of R6 (for examples, FACTS, etc).

It is also recommended to append / clarify the first sentence with respect to ownership -- as follows:

For applicable units of inverter based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2, each Generator Owner, or Transmission Owner that owns a Facility listed in Section 4.2.4 or 4.2.5 shall provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

AECI agrees with EEI's comments:

EEI does not agree that EMT models are needed everywhere at this time. We also do not agree that the industry is sufficiently prepared to develop large scale EMT models at this time. Instead, these models should be limited to those areas where the needs are most urgent and as directed by the responsible Transmission Planner (TP), in cooperation with the responsible Planning Coordinator (PC). For this reason, criteria should be developed by the SDT to help guide the industry when EMT models are needed. This will ensure that lessons learned can be developed and applied over time as these models become necessary. We recommend the following edits to Requirement R6:

R6: **After a formal analysis by the Transmission Planner (TP) and as a result of their inability to conduct accurate dynamic simulations that reflect and assess BES reliability performance that due to the growth of IBRs (or in cases where IBRs are being installed in areas with low short circuit strength) the TP shall submit data requests to affected GOs and TOs to** provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the **effected** Facilit**ies** to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following:

Requirement R6, subpart 6.2 and the use of the term "large signal disturbances" should be clarified. Currently, small signal disturbances are tested and verified by injecting a small step change (e.g., a 2.5% step change) into excitation and frequency response controls. A large disturbance potentially means something that would be outside of a control system or units deadband. EEI does not agree that entities should be required to inject large signal disturbances which could damage equipment or cause a system disturbance for a mandatory test. For this reason, clarity regarding what was intended by this language should be provided.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	No
Document Name	

Comment

AZPS does not support Requirement R6 for the following reasons:

The EMT modeling requirement seems excessive for this application as there has not been sufficient justification of why this level of detail is required. Concerns for large-signal disturbance behavior are already being addressed by recommended practices such as PRC-024 and the NERC “BPS-Connected Inverter-Based Resource Performance Reliability Guideline.” While these do not directly address modeling, they require that the type of behavior that was witnessed during the Blue Cut fire is mitigated. Since we are currently setting protection to be broad enough to ride through these disturbances, requiring EMT models in addition to positive sequence models would add significant cost and time to model verification without creating additional reliability.

Any protection and limiters should already be modeled adequately based on the revised R4 and R5. Sub-Synchronous Resonance and negative/zero sequence events affect traditional generation as well. Even though EMT modeling has been available for decades, it has not been required to develop these models, provide them to other entities, or shown that doing so will provide any meaningful increase in system reliability. Transmission planners do not currently use these models in their positive sequence studies, and very few transmission planners have the capability of using these types of models today.

As a GO, it would be nearly impossible to create and validate an EMT model without manufacturer support. PRC-024 and industry best practices should provide adequate safety margin for the system by requiring that the equipment not trip within the no-trip zone. Creating an EMT model is unreasonably burdensome for the rare event where this information might be useful and a large enough system disturbance to adequately validate these models would be incredibly rare, and difficult or impossible to stage. Furthermore, MOD-33 already requires system model validation for these types of events.

If the requirement to use EMT models is not removed from the standard, AZPS supports the following recommendation submitted by EEI: “EEI does not agree that EMT models are needed everywhere at this time. We also do not agree that the industry is sufficiently prepared to develop large scale EMT models at this time. Instead, these models should be limited to those areas where the needs are most urgent and as directed by the responsible Transmission Planner (TP), in cooperation with the responsible Planning Coordinator (PC). For this reason, criteria should be developed by the SDT to help guide the industry when EMT models are needed. This will ensure that lessons learned can be developed and applied over time as these models become necessary.”

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation does not agree with the addition of EMT models due to the limited number of subject matter experts in the industry, equipment manufacturers and vendors that are able to implement the requirements in this standard as stated in the implementation plan.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	
Comment	

Constellation does not agree with the addition of EMT models due to the limited number of subject matter experts in the industry, equipment manufacturers and vendors that are able to implement the requirements in this standard as stated in the implementation plan.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	

Comments: EEI does not agree that EMT models are needed everywhere at this time. We also do not agree that the industry is sufficiently prepared to develop large scale EMT models at this time. Instead, these models should be limited to those areas where the needs are most urgent and as directed by the responsible Transmission Planner (TP), in cooperation with the responsible Planning Coordinator (PC). For this reason, criteria should be developed by the SDT to help guide the industry when EMT models are needed. This will ensure that lessons learned can be developed and applied over time as these models become necessary. We recommend the following edits to Requirement R6:

R6: **After a formal analysis by the Transmission Planner (TP) and as a result of their inability to conduct accurate dynamic simulations that reflect and assess BES reliability performance that due to the growth of IBRs (or in cases where IBRs are being installed in areas with low short circuit strength) the TP shall submit data requests to affected GOs and TOs to For applicable units of inverter based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2, each Generator Owner or Transmission Owner shall** provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the **effected** Facilit**ies** to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following:

Requirement R6, subpart 6.2 and the use of the term “large signal disturbances” should be clarified. Currently, small signal disturbances are tested and verified by injecting a small step change (e.g., a 2.5% step change) into excitation and frequency response controls. A large disturbance potentially means something that would be outside of a control system or units deadband. EEI does not agree that entities should be required to inject large signal disturbances which could damage equipment or cause a system disturbance for a mandatory test. For this reason, clarity regarding what was intended by this language should be provided.

Likes 0	
Dislikes 0	

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

EEI does not agree that EMT models are needed everywhere at this time. We also do not agree that the industry is sufficiently prepared to develop large scale EMT models at this time. Instead, these models should be limited to those areas where the needs are most urgent and as directed by the responsible Transmission Planner (TP), in cooperation with the responsible Planning Coordinator (PC). For this reason, criteria should be developed by the SDT to help guide the industry when EMT models are needed. This will ensure that lessons learned can be developed and applied over time as these models become necessary. We recommend the following edits to Requirement R6:

R6: **For applicable units of inverter based resources (IBRs), identified under R1, subpart 1.2, GOs and TOs shall** provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the **effected** Facilit**ies** to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following:

Requirement R6, subpart 6.2 and the use of the term “large signal disturbances” should be clarified. Currently, small signal disturbances are tested and verified by injecting a small step change (e.g., a 2.5% step change) into excitation and frequency response controls. A large disturbance potentially means something that would be outside of a control system or units deadband. EEI does not agree that entities should be required to inject large signal disturbances which could damage equipment or cause a system disturbance for a mandatory test. For this reason, clarity regarding what was intended by this language should be provided.

Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Derek Brown, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) to question #5.

Likes 0	
Dislikes 0	
Response	

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	

Xcel Energy generally supports the comments of EEI. Below are Xcel Energy comments that indicate additional or differing concerns.

As indicated in response to Questions 3 and 4 of this comment form, Xcel Energy disagrees with including protective system trips in the Standard for Requirement 6.3. Xcel Energy maintains that relay settings are static, not dynamic as the Standard title indicates. Relay settings are already included in other PRC Standards and PRC Standards manage those settings. As indicated in Questions 3 and 4, these modifications would require Generator Owners (GO) to perform unnecessary model revisions as relay settings change more frequently and it will create an administrative burden with the number of modeling revisions and significantly increase costs for GOs when protective system changes are made. Relay settings can be provided to Transmission Planners (TP) via PRC Standard communications and can also be provided in different formats and still achieve the same benefit; without causing GOs to perform unnecessary modeling. In addition, the TP can request protection system settings through MOD-032 data specifications if necessary.

Likes 0	
Dislikes 0	
Response	

Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	

Portland General Electric Company supports the comments provided by EEI.

Likes 0	
Dislikes 0	
Response	

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

WEC Energy Group supports EEI comments.

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA uses standard HVDC models available in grid simulation packages like Siemens PSS/E, GE PSLF or PowerWorld. The model data must match model structure that is implemented in the industry used grid simulators.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports EEI and NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
As a Generator Owner and Transmission Owner we will continue to provide requested model data, but at this time there are no NERC approved EMT models with limited software/expertise.	
Likes 0	

Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Is the OEM not responding to a request for an attestation a valid reason for not being able to attain one? Why do we need an attestation if we are going to validate the model anyway?

Likes 0	
Dislikes 0	

Response

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw

Answer	No
Document Name	

Comment

Based on the existing generation interconnection process in ERCOT, we recommend changing “Transmission Planner” to “Transmission Planner or Planning Authority” in proposed R6. In ERCOT as well as other regions, there are instances in which the Transmission Owner and the Transmission Planner are the same entity. The spirit of the proposed requirement suggests a collaboration of checks and balances to verify modeling accuracy. Requiring a Transmission Owner to send modeling information to itself would not achieve the intended verification of modeling accuracy. Therefore, we advise adding “Planning Authority” in conjunction with “Transmission Planner” for all instances in R6.

Regarding proposed R6.2. and R6.4., attempting to validate a recorded field response against the EMT model will require building an area EMT case. ERCOT does not develop or maintain an official PSCAD case for its Transmission Planners. Building EMT cases for small individual areas would be a substantial undertaking. Instead, it would be more efficient and cost effective for Transmission Planners to validate the EMT models with a simpler, controllable infinite bus test rather than validating them through a full EMT case. Thus, we suggest revising proposed R6.2 and 6.4 to allow Transmission Planners within ERCOT to use this alternative method to validate the EMT models.

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2

Answer	No

Document Name	

Comment
Footnote 11, which is associated with R6, should be changed from “LCC HVDC facilities are excluded from the dynamic voltage or VAR event portion of the requirement” to “LCC HVDC facilities including associated automatically controlled switched shunts and reactors that operate within the transient stability timeframe are ***not*** excluded from the dynamic voltage or VAR event portion of the requirement.”

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	

Comment
CenterPoint Energy supports the comments as submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	

Comment

We recommend replacement of “Transmission Planner” with “Transmission Planner and/or Planning Coordinator” in Requirements R6

As mentioned in MRO NSRF’s response to question 1, we propose the SDT reduce the barriers and increase the ease of obtaining EMT models for applicable functional entities; e.g. Planning Coordinator and Transmission Planners, as EMT models tend to be manufacturer specific and guarded by manufacturers from a confidentiality standpoint. To accomplish this, we propose the following modification to R6.

R6. For applicable units of inverter based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2, each Generator Owner or Transmission Owner shall provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner and Planning Coordinator, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

The MRO NSRF has concerns about the implementation of required EMT models. While the MRO NSRF understands there is a need, it recommends a

5-year implementation process due to the human, data, training, and computer resources.

• EMT models are complex and it will take 5-years to train personnel and develop EMT models.

• There are a limited amount of consultants available to develop EMT models. A 2-year implementation process will cause a bottleneck on available resources.

• EMT models require data that positive sequence dynamics models don’t. Additional new data on new systems must be gathered first to then model. This will take time.

• Entities will need time to identify and purchase new software for EMT models.

• An EMT simulation for something like a NERC Odessa event will require a lot of computer power.

• Industry will need time to develop model conversion software, something like CAPE to EMT model conversions to ease the labor issue, speed model development and keep model accuracy to acceptable levels.

• Verifying EMT models in R6 and R6.1 – R6.4

o For R6.1 and concerns that Original Equipment Manufacturers (OEMs) aren’t NERC entities.

o The MRO NSRF suggests replacing the OEM attestation concept with specifications that can be placed in OEM contracts as a superior alternative, “R6.1 Model(s) shall have all inverter control modes, control blocks, and protections represented, as applicable and be representative and accurate of the equipment installed at generation resource.”

o For R6.2 The SDT needs to better define what is a large system disturbance. Small signal disturbances are tested and verified by injecting a small step change into excitation and frequency response controls. An example would be a 2.5% step change. A large disturbance potentially means something that would be outside of a control system or units deadband. Entities should not be required to inject large signal disturbances which could damage equipment or cause a system disturbance for a mandatory test.

o R6.2 and R6.3, the increased emphasis on EMT validation and large signal testing will drive the inclusion of additional generator models such as:

□ Over Excitation Limiters and protection trips

□ Under Excitation Limiters and protection trips

□ Other protective models

o R6.4, will require a lot of new high speed digital fault recorder technology probably at both the generator low side and high side busses. There are lots of current, voltage, and control signals to monitor to verify something as complex as an EMT model.

o It’s the MRO NSRF’s understanding that EMT models are computer CPU intensive and only a very limited set of runs are possible. As an example, it’s believed that one 5 second run can take several hours.

The MRO NSRF believe the verification and validation definitions need clarification. Specifically, the SDT needs to state clearly in the requirements that large signal verification or validations could be completed using simulations.

The use of verification as defined in applicability section 6.1 leaves open the high probability of a never ending open loop activity of model production for IBR sites that do not react identically to varying disturbance signals.   Each system disturbance is likely to “look” different to the IBR equipment. Requiring a model that is 100% accurate for all types of system disturbances is not equitable to the stakeholders taxed with the obligation to do so. The equipment owner will never finish developing a model that is guaranteed to predict IBR controls with 100% certainty. A continual remodeling effort

will never end.	
Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	No
Document Name	
Comment	
R6.1 requires that the OEM state that the EMT model represents the IBR equipment supplied by the OEM. This sub requirement should also require that the OEM state that the EMT model is equivalent to the positive-sequence model provided to satisfy R4 or R5. While the EMT and positive-sequence models are utilized by different tools for different types of analysis, the OEM should be required to document that the EMT and positive-sequence models are as accurate and similar as the tools allow the physical equipment to be represented.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI for Question #5.

Submitted on behalf of Exelon, Segments 1 & 3

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	

Comment

MidAmerican supports MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	

Response

James Baldwin - Lower Colorado River Authority - 1	
Answer	No
Document Name	

Comment

R6.1 and R6.2 state that if attestation from the OEM and device test results are not obtainable, the GO or TO shall document the reason. LCRA TSC thinks it would be beneficial to add a footnote defining what would qualify as an acceptable reason.

Likes 0	
Dislikes 0	

Response

Durga Gautam - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment

R6.3: While listing the voltage and frequency protections in positive sequence models is straightforward, full protection lists in EMT models are not (from the IBR equipment perspective). OEMs cannot list all associated parameters while maintaining a reasonable level of complexity and the required level of propriety in the communication. For the IBR unit aspect of 6.3, the IBR OEM should only have to confirm that all relevant protections for the IBR unit are included in the EMT model.

R6.2 and 6.5: Please provide a reference for definition of a large signal disturbance, as OEM's will be unable to perform testing on an unlimited number of fault types, should they be requested differently by various RTO's. The industry should agree on standard large signal tests for best coordination in the execution of this standard, such as those defined by IEC 61400-21.

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5

Answer	No
Document Name	

Comment

City of Austin dba Austin Energy requests the SDT provide clarification on the term **large signal disturbances** in R6, subparts 6.2 and 6.5.

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 has the following concerns and /or comments:

General:

a. The NAGF supports EEI's comments re. the appropriateness and / or necessity of large scale EMT models. Per NERC's risk based approach, these models should be limited to the ares where the needs are most urgent and as directed by the responsible Transmission Planner (TP) in cooperation with the Planning Authority (PA). For this reason, we support EEI's suggestion that criteria be developed by the SDT to help guide the industry when EMT models are needed. This will ensure that adequate tools are developed for industry use and lessons learned can be applied over time in areas as these models become necessary.

The NAGF supports EEI's recommended changes: R6: After a formal analysis by the Transmission Planner (TP) and as a result of their inability to conduct accurate dynamic simulations that reflect and assess BES reliability performance that due to the growth of IBRs (or in cases where IBRs are being installed in areas with low short circuit strength) the TP shall submit data requests to affected GOs and TOs for applicable units of inverter based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2, each Generator Owner or Transmission Owner shall provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the effected Facilities to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following: Requirement R6, subpart 6.2 and the use of the term "large signal disturbances" should be clarified. Currently, small signal disturbances are tested and verified by injecting a small step change (e.g., a 2.5% step change) into excitation and frequency response controls. A large disturbance potentially means something that would be outside of a control system or units deadband. EEI does not agree that entities should be required to inject large signal disturbances which could damage equipment or cause a system disturbance for a mandatory test. For this reason, clarity regarding what was intended by this language should be provided.

2. We have concerns with R6.1 because OEMs are not NERC entities and have no enforceable obligation to provide information on old equipment or are no longer available.

3. We believe that R6.2 needs to include the same OEM attestation wording as R6.1. As currently written, the GO and TO is the entity responsible for providing a device test or possible a large signal device test. GO's and TO's are not in the device testing business – we believe the requirement as written provides little value, especially for the expected cost to comply.

4. Most existing facilities do not have high speed digital fault recorder technology probably at both the generator low side and high side busses for recording the signals required by R6.4 to model a facility. There are lots of current, voltage, and control signals to monitor to verify something as complex as an EMT model.

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 agrees with the comments provided by EEI that EMT models are not required everywhere at this time and that criteria should be developed to help guide the industry when EMT models are required. PG&E also agrees with the recommended modifications to R6.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis

Answer	No
Document Name	

Comment

As mentioned in SRC’s response to Question 2, the SRC proposes that the SDT reduce the barriers and increase the ease of obtaining EMT models for applicable functional entities; e.g. Planning Authority, as EMT models tend to be manufacturer specific and guarded by manufacturers from a confidentiality standpoint. To accomplish this, we propose the following modification to R6. **R6.** For applicable units of inverter based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2, each Generator Owner or Transmission Owner shall provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner and Planning Authority, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s) and accompanying information shall include at a minimum the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
R6.1 requires that the OEM state that the EMT model represents the IBR equipment supplied by the OEM. This subrequirement should also require that the OEM state that the EMT model is equivalent to the positive-sequence model provided to satisfy R4 or R5. While the EMT and positive-sequence models are utilized by different tools for different types of analysis, the OEM should be required to document that the EMT and positive-sequence models are as accurate and similar as the tools allow the physical equipment to be represented.	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	No
Document Name	
Comment	
Use of the term “large signal disturbances” should be clarified in Requirement R6, subparts 6.2 and 6.5 to help prevent confusion after the Standard is approved.	

Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	No
Document Name	
Comment	
No. CPS Energy agrees with comments submitted by EEI and others.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports the comments submitted by LPPC.	
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; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	No
Document Name	
Comment	
R6 contains validation provisions that do not directly reflect a means of verifying the as-installed configuration of the equipment and response to an	

EMT, short of an "in-service" verification. This should be addressed by an explicit pre-operational verification of transient response.	
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 proposes that the SDT reduce the barriers and increase the ease of obtaining EMT models for applicable functional entities; e.g. Planning Authorities and Transmission Planners, as EMT models tend to be manufacturer specific and guarded by manufacturers from a confidentiality standpoint.

Southern Company has concerns with R6.1 because OEMs are not NERC entities and have no enforceable obligation to provide information on old equipment or are no longer available.

Southern Company believes that R6.2 needs to include the same OEM attestation wording as R6.1. As currently written, the GO and TO is the entity responsible for providing a device test or possible a large signal device test. GO's and TO's are not in the device testing business – we believe the requirement as written provides little value, especially for the expected cost to comply.

The use of verification as defined in applicability section 6.1 leaves open the high probability of a never ending open loop activity of model production for IBR sites that do not react identically to varying disturbance signals. Each system disturbance is likely to "look" different to the IBR equipment. Requiring a model that is 100% accurate for all types of system disturbances is not equitable to the stakeholders taxed with the obligation to do so. The equipment owner will never finish developing a model that is guaranteed to predict IBR controls with 100% certainty. A continual remodeling effort will never end.

Southern Company agrees with EEI's comments on this item: EMT models are not needed everywhere at this time and the industry is not sufficiently prepared to develop large scale EMT models at this time.

Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	

Answer	No
Document Name	
Comment	

R6.1 and R6.2 state that if attestation from the OEM and device test results are not obtainable, the GO or TO shall document the reason. LCRA TSC thinks it would be beneficial to add a footnote defining what would qualify as an acceptable reason.

Likes 0	
Dislikes 0	
Response	

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	
Comment	

It i*s more appropriate for the PC/TP to define the EMT model characteristics in MOD-032 than in MOD-026, and we feel that R6 is overly prescriptive for standard language. This is better placed in the technical rationale for the PC/TP to use/consider when developing their modeling criteria. Furthermore, did the SDT consult with OEM's about the attestation requested in 6.1? This seems like a big ask, and we would expect most OEMs will refuse or say the details of the final plant design are too complex for them to attest to this. The language about simply "documenting a reason" is a way to get out of an undesired situation and makes these requirements ineffectual. It would be better to recommend that GOs/TOs put things like this in facility construction and PPA agreements, outside of the standards. For 6.4, it is not clear how a facility is supposed to provide a validation without a real event occurring. In a facility with so many devices distributed throughout, they will not be able to "simulate" power system characteristics.*

Likes 0	
Dislikes 0	
Response	

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	
Comment	

ERCOT believes the OEM attestation in R6.1 is not the best way to accomplish the desired result because equipment and settings may change during commissioning. The equipment owner should have primary responsibility to obtain an attestation or confirmation the model represents the equipment as commissioned.

Likes 0	

Dislikes 0	
Response	
James Howell - Southern Company - Southern Company Generation - 5	
Answer	No
Document Name	
Comment	
See Southern Company Comments	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
R1 requires the Transmission Planner and its Planning Authority (Coordinator) to “develop dynamic model requirements and processes” and to make them “available to the Generator Owner and Transmission Owner”. R6 then sets specific minimum requirements for “verified model(s) and accompanying information” to be provided to the Transmission Planner. The standard should focus on verifiable modeling data that are necessary for performing simulations and avoid requirements for superfluous information. The standard should not set “at a minimum” expectations in R6 while requiring the TP/PC to establish their dynamic modeling data needs in R1, potentially creating a conflict.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
Agree with comments submitted by BPA.	
Likes 0	

Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
More information on Footnote 9 is required. Notably, what is meant by "factory type test, hardware in the loop test, or other manufacture test." Also, with respect to R6.2 and R6.5, more information is needed on the definition of a "large signal disturbance."	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Yes, Consumers approved this question, however, there are some technical issues directly involved with R4 and R5 that need to be clarified.	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Yes, Consumers approved this question, however, there are some technical issues directly involved with R4 and R5 that need to be clarified.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP recommends that the content of the following sentence from the Technical Rationale in reference to the R6.5 term “large-signal disturbance” be factored into the standard itself, either as a subrequirement or a footnote, so that the term may be adequately defined and not open to wide interpretation that could detract from the effectiveness of the R6.5 verification: “The specific large-signal simulation tests that may be run on both EMT and positive sequence models for benchmarking comparisons may include balanced and unbalanced faults, delayed clearing phase-ground point of interconnection faults, temporary or transient over-voltages, rates of change of frequency (ROCOF), varying short circuit levels (or ratios), and phase angle jumps as may be specified by the Transmission Planner under R1.3.”.	
Likes 0	
Dislikes 0	

Response	
Aric Root - CMS Energy - Consumers Energy Company - 4	
Answer	Yes
Document Name	
Comment	

Yes, Consumers approved this question, however, there are some technical issues directly involved with R4 and R5 that need to be clarified.

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	

SPP can support the proposed language in Requirements R6. However, there is a concern that entities like the PC, will not have access to modeling data such as the Phase Look Loop Data (PLL) for our Short Circuit Ratio (SCR) screening Analysis which will help determine the need for an Electromagnetic Transient (EMT) study. For clarity, the SCR analysis doesn't provide the entire picture, however, the EMT study can provide a detailed picture on identified reliability issues. The PC should be include in the requirement language (shown below) to enable them to received the verified dynamics and EMT models from the GOs and TOs.

R6. For applicable units of inverter based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2, each Generator Owner or Transmission Owner shall provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner and ***Planning Coordinator***, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

Furthermore, there is another concern about data retrieval, specifically, the Five (5) year data retrieval via MOD-026 and MOD-027 (performance requirement) in reference to modified/material changes. From our perspective, this timing requirement may need to be shorten as it doesn't align with MOD-032 reporting requirements. Currently, there are no requirements that requires an entity to report their modified/material changes per MOD-026 and MOD-027 in which properly aligns with the MOD-032 reporting requirements.

SPP suggests the MOD-026 drafting team coordinate with the MOD-032 drafting team to ensure the appropriate data is discussed and addressed to help meet the needs to conduct the SCR screening to verify and confirm the need for an EMT study.

Additionally, the drafting team should consider a shorter timing report requirement in reference to the modified/material changes which would help MOD-026/MOD-027 and MOD-032 reporting requirements align.

Likes 0	
Dislikes 0	

Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
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	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Dwanique Spiller On Behalf of: Dwanique Spiller, Berkshire Hathaway - NV Energy, 5; - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Pam Syrjala, Salt River Project, 5, 3, 1, 6; Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
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	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
For Parts 6.1 and 6.2 should there be some level of criteria identified of acceptable reasons the attestation (6.1) or the test results (6.2) are not available. The current language appears to leave reason(s) open, which is difficult to audit.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment

Texas RE seeks clarification on the difference in the terms “IBR unit(s)” and “plant” as used in Requirement Parts 4.3 and 6.3. The addition of “or plant” appears in some parts, but not others.

Likes 0

Dislikes 0

Response

Michael Jones - National Grid USA - 1

Answer

Document Name

Comment

National Grid supports EEI's comments.

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

The ITC Standards Under Development Team has received no response to submit from the Standard Owners

Likes 0

Dislikes 0

Response

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County

Answer

Document Name

Comment

N/A R6 is only for inverter based resources.

Likes 0	
Dislikes 0	

Response

6. Do you agree the language proposed in MOD-026-2 Requirements R7, R8, and R9? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Glenn Pressler - CPS Energy - 3	
Answer	No
Document Name	
Comment	
No. CPS Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	No
Document Name	
Comment	
The SRC does not agree with the proposed Requirements: R4, R7 and R9 and requests the following: GOs should not make changes to their facilities that impact models without first obtaining concurrence. Both the current and proposed language appear to show “after the fact” submittal and review is allowed by using the word ”within”. There should be a requirement to have the model checked 180 days prior to installing any equipment changes. TPs should also have a process to handle emergency changes (e.g. broke fix). There should be another requirement after installation to provide evidence that the actual installation operates as expected. R9 second bullet should provide TPs the authority to get corrections in an acceptable timeframe, not having to negotiate to “mutual” agreement.	
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 agrees with the EEI comments that 180 days is not sufficient and be changed to 365 days, footnote #13 should be incorporated into the body of the Standard, and EEI's recommended changes to Requirement R8.	
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 has the following concerns and /or comments: General: The NAGF supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
: Requirement R7 employs a confusing run-on sentence. Requirement R7 should be revised to: Each Generator Owner or Transmission Owner shall provide to its Transmission Planner an updated verified model(s) or a mutually agreed upon plan with its Transmission Planner to verify the model, mutually agreeable to its Transmission Planner, in accordance with Requirements R2–R6 to its Transmission Planner within 180 calendar days of making a change to in-service equipment specified in Part 2.2, 3.2, 4.2, 5.2, or 6.3 that alters the equipment response characteristic.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren requests that the TP is given 120 days to provide a written response for to the Generator Owner or Transmission Owner that their models is accepted or denied as part of R8. Ameren feels that more time is needed to verify the data than in the past since it will include EMT models. We also believe that there needs to be a path to resolve a disagreement between the Transmission Planner and Generator or Transmission Owner on what models are acceptable. Finally, there needs to be a method to resolve a dispute between the two entities needs to be included in R9.	
Likes 0	
Dislikes 0	
Response	
Durga Gautam - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The criteria for re-verification in R7 which states "…that alters the equipment response characteristic" is vague and open to interpretation. This may be intended to be clarified by the RTO's during implementation of the standard, but can further clarification on this be provided in the MOD, in order to achieve the true goals of the standard while avoiding a large number of unnecessary verifications?	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican supports MRO NSRF and EEI comments.	
Likes 0	
Dislikes 0	

Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI for Question #6. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	
The MRO NSRF recommends replacement of "Transmission Planner" with "Transmission Planner and/or Planning Coordinator" in Requirements R7., R8., and R9. The MRO NSRF has concerns with the "large" signal disturbances. The MRO NSRF suggests defining large system disturbance by moving Attachment 1, Note 1 to the top in Section 6. **Reference:** See the technical rationale, section R4 where it's stated R4 is specific to positive sequence modeling and reflects the intent of the SAR to	

verify both small signal performance via staged testing (termed as validation) and large signal performance via documentation and analysis exercises.	
Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy supports the comments as submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Based on the existing generation interconnection process in ERCOT, we recommend changing “Transmission Planner” to “Transmission Planner or Planning Authority” in proposed R7. In ERCOT as well as other regions, there are instances in which the Transmission Owner and the Transmission Planner are the same entity. The spirit of the proposed requirement suggests a collaboration of checks and balances to verify modeling accuracy. Requiring a Transmission Owner to send modeling information to itself would not achieve the intended verification of modeling accuracy. Therefore, we advise adding “Planning Authority” in conjunction with “Transmission Planner” for all instances in R7.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	

Black Hills Corporation supports EEI comments. In addition to transmission planner, planning coordinator needs to be added to the language.

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	No
Document Name	
Comment	
WEC Energy Group supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
While AEP has no objections to the language proposed in MOD-026-2 Requirements R7, R8, and R9, we do recommend that a footnote be added to R9 to make it clear that the Transmission Planner's request for a model review may also be justified on the basis of the simulated unit or plant response not matching the measured unit or plant response to an event as in the existing MOD-026 and MOD-027. Also, the language provided in the mapping document on page 6 for R9 differs from that in the proposed standard R9 text and we prefer the language as provided in the mapping document ("…or a technical justification for model review…") which suggests a model review may be initiated for reasons not limited to "identified model or accompanying information deficiencies".	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Dwanique Spiller, Berkshire Hathaway - NV Energy, 5; - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	

Comment	
R7 should be updated to also include that the GO or TO provide updated protection models specified in R2.3, R3.3, R4.3 and R5.3 when protection settings are modified.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports EEI's comment.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Derek Brown, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) to question #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 agree that 180 days is sufficient, noting that vendors often delay providing needed documentation (e.g., 60-90 days before receipt of documentation is not uncommon). We further note that the current version of MOD-026 & 027 provide entities with 365 days to update the TP with new models. For these reasons, EEI asks that the proposed draft be changed from 180 days to 365 days.

Next, EEI does not agree the information provided in footnote #13 should be left as a footnote. Footnote #13 contains important information regarding the expectations of changes to equipment that alter resource response characteristic, therefore this information should be contained in the body of the standard not a footnote.

EEI recommends the following changes to Requirement R8 add needed clarity to this requirement, and provide the TP with 120 calendar days to review and provide a written response to the GOs and TOs (noting expanded data reviews will be required, including EMT models). See suggested edits to R8 below:

Each Transmission Planner shall review **materials submitted pursuant to requirements R2-R7 and R9. The Transmission Planner will send a written response to the submitter within 120 calendar days from receiving each submission.** The written response shall include one of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

- Notification of acceptance: the model and accompanying information meet the acceptance criteria established in Requirement R1, or
- Notification of denial: the model and accompanying information does not meet acceptance criteria established in Requirement R1, or information submitted is incomplete. The notification of denial shall include an explanation and supporting evidence.

EEI suggests that Requirement R9 should include a dispute resolution process in order to resolve disagreements between the TP and GOs and TOs on the acceptability of the models provided.

EEI also recommends that the Planning Coordinator also be added to these requirements.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	
Comment	

Comments: EEI does not agree that 180 days is sufficient, noting that vendors often delay providing needed documentation (e.g., 60-90 days before receipt of documentation is not uncommon). We further note that the current version of MOD-026 & 027 provide entities with 365 days to update the TP with new models. For these reasons, EEI asks that the proposed draft be changed from 180 days to 365 days.

Next, EEI does not agree the information provided in footnote #13 should be left as a footnote. Footnote #13 contains important information regarding the expectations of changes to equipment that alter resource response characteristic, therefore this information should be contained in the body of the standard not a footnote.

EEI recommends the following changes to Requirement R8 add needed clarity to this requirement, and provide the TP with 120 calendar days to review and provide a written response to the GOs and TOs (noting expanded data reviews will be required, including EMT models). See suggested edits to R8 below:

Each Transmission Planner shall review **materials submitted pursuant to requirements R2-R7 and R9. The Transmission Planner will send a written response to the submitter within 120 calendar days from receiving each submission.** The written response shall include one of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

{C}· Notification of acceptance: the model and accompanying information meet the acceptance criteria established in Requirement R1, or

{C}· Notification of denial: the model and accompanying information does not meet acceptance criteria established in Requirement R1, or information submitted is incomplete. The notification of denial shall include an explanation and supporting evidence.

EEI suggests that Requirement R9 should include a dispute resolution process in order to resolve disagreements between the TP and GOs and TOs on the acceptability of the models provided.

EEI also recommends that the Planning Coordinator also be added to these requirements.

Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

For R7, ATC suggests the following change to assure that the updated models will be verified before equipment is installed. The word “within” could mean after installation.

“Each Generator Owner or Transmission Owner shall provide an updated verified model(s) or a mutually agreed upon plan with its Transmission Planner to verify the model in accordance with Requirements R2–R6 to its Transmission Planner within 180 calendar days prior to of making a change

to in-service equipment specified in Part 2.2, 3.2, 4.2, 5.2, or 6.3 that alters the equipment response characteristic”	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	

AECI agrees with EEI’s comments:

EEI does not agree that 180 days is sufficient, noting that vendors often delay providing needed documentation (e.g., 60-90 days before receipt of documentation is not uncommon). We further note that the current version of MOD-026 & 027 provide entities with 365 days to update the TP with new models. For these reasons, EEI asks that the proposed draft be changed from 180 days to 365 days.

Next, EEI does not agree the information provided in footnote #13 should be left as a footnote. Footnote #13 contains important information regarding the expectations of changes to equipment that alter resource response characteristic, therefore this information should be contained in the body of the standard not a footnote.

EEI recommends the following changes to Requirement R8 add needed clarity to this requirement, and provide the TP with 120 calendar days to review and provide a written response to the GOs and TOs (noting expanded data reviews will be required, including EMT models). See suggested edits to R8 below:

Each Transmission Planner shall review **materials submitted pursuant to requirements R2-R7 and R9. The Transmission Planner will send a written response to the submitter within 120 calendar days from receiving each submission.** The written response shall include one of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

· Notification of acceptance: the model and accompanying information meet the acceptance criteria established in Requirement R1, or

· Notification of denial: the model and accompanying information does not meet acceptance criteria established in Requirement R1, or information submitted is incomplete. The notification of denial shall include an explanation and supporting evidence.

EEI suggests that Requirement R9 should include a dispute resolution process in order to resolve disagreements between the TP and GOs and TOs on the acceptability of the models provided.

EEI also recommends that the Planning Coordinator also be added to these requirements.

Likes 0	
Dislikes 0	
Response	

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

FE agrees with EEI’s comments:

EEI does not agree that 180 days is sufficient, noting that vendors often delay providing needed documentation (e.g., 60-90 days before receipt of documentation is not uncommon). We further note that the current version of MOD-026 & 027 provide entities with 365 days to update the TP with new models. For these reasons, EEI asks that the proposed draft be changed from 180 days to 365 days.

Next, EEI does not agree the information provided in footnote #13 should be left as a footnote. Footnote #13 contains important information regarding the expectations of changes to equipment that alter resource response characteristic, therefore this information should be contained in the body of the standard not a footnote.

EEI recommends the following changes to Requirement R8 add needed clarity to this requirement, and provide the TP with 120 calendar days to review and provide a written response to the GOs and TOs (noting expanded data reviews will be required, including EMT models). See suggested edits to R8 below:

Each Transmission Planner shall review **materials submitted pursuant to requirements R2-R7 and R9. The Transmission Planner will send a written response to the submitter within 120 calendar days from receiving each submission.** The written response shall include one of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

· Notification of acceptance: the model and accompanying information meet the acceptance criteria established in Requirement R1, or

· Notification of denial: the model and accompanying information does not meet acceptance criteria established in Requirement R1, or information submitted is incomplete. The notification of denial shall include an explanation and supporting evidence.

EEI suggests that Requirement R9 should include a dispute resolution process in order to resolve disagreements between the TP and GOs and TOs on the acceptability of the models provided.

EEI also recommends that the Planning Coordinator also be added to these requirements.

Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Suggestions:

1. Modify R7 to specify that R2, R3, R4, R5, and R6 can be complied with and submitted separately to ensure there is no confusion between GOs and TPs. This action would also assist with audits.
2. Remove note 13. This action expands audit scope and the risk of non-compliance outweighs the benefits provided to reliability.
3. R1 is open ended. Specifics to comply should be detailed in this standard as in the existing MOD-026 and MOD-027 standards.
4. M8: Remove the need to supply review date of submitted model and accompanying information. Response within the 90 days is sufficient.
5. Provide clarity on how the 180 day requirement applies. Existing language could be read that it only applies to the agreed upon plan, and not to the updated model.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Model verification for a given contingency should be maintained within the responsibility of the Transmission Planner, not the GO.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Model verification for a given contingency should be maintained within the responsibility of the Transmission Planner, not the GO.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

EEI does not agree that 180 days is sufficient, noting that vendors often delay providing needed documentation (e.g., 60-90 days before receipt of documentation is not uncommon). We further note that the current version of MOD-026 & 027 provide entities with 365 days to update the TP with new models. For these reasons, EEI asks that the proposed draft be changed from 180 days to 365 days.

Next, EEI does not agree the information provided in footnote #13 should be left as a footnote. Footnote #13 contains important information regarding the expectations of changes to equipment that alter resource response characteristic, therefore this information should be contained in the body of the standard not a footnote.

EEI recommends the following changes to Requirement R8 add needed clarity to this requirement, and provide the TP with 120 calendar days to review and provide a written response to the GOs and TOs (noting expanded data reviews will be required, including EMT models). See suggested edits to R8 below:

Each Transmission Planner shall review **materials submitted pursuant to requirements R2-R7 and R9. The Transmission Planner will send a written response to the submitter within 120 calendar days from receiving each submission. the verified model and accompanying information, an updated verified model provided under Requirement R7, or a written response provided under Requirement R9, provided by a Generator Owner or Transmission Owner, and provide a written response to the submitter within 90 calendar days from receiving the verified model information.** The written response shall include one of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

{C}· Notification of acceptance: the model and accompanying information meet the acceptance criteria established in Requirement R1, or

{C}· Notification of denial: the model and accompanying information does not meet acceptance criteria established in Requirement R1, or information submitted is incomplete. The notification of denial shall include an explanation and supporting evidence.

EEI suggests that Requirement R9 should include a dispute resolution process in order to resolve disagreements between the TP and GOs and TOs on the acceptability of the models provided.

EEI also recommends that the Planning Coordinator also be added to these requirements.

Likes 0	
Dislikes 0	

Response

Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	

Comment

Agree with comments submitted by PUD No. 1 of Chelan County, WA.

Likes 0	
Dislikes 0	

Response

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	

1. R7 now requires the GO to provide a "mutually agreed upon plan" to the TP rather than just a "plan". This will require that entities have evidence the test plan was "mutually agreed upon". As long as the plan notification and the model submittal meet the deadline, and the submittal meets the requirements of R2, why do entities need to track another piece of evidence that the plan is "mutually agreed upon?"

2. For R7, Attachment 1 Row 6: The "required action" column now requires that the model be submitted from GO to TP within 180 days after the "mutually agreed upon plan" was sent from GO to TP. In the existing MOD-026-1 and MOD-027-1, the same requirement is 365 days. Why did this deadline get shorter? The change to the deadline seems in conflict with comments made in the webinar that was released by NERC for MOD-026-2 regarding changes to Attachment 1 where it was commented that no changes were made to the administration of the deadlines in Attachment-1. We question whether this was an intentional change to the deadline.

3. R7, Attachment 1, Row 6, "required action" column: "Transmit the verified model and accompanying information to the Transmission Planner within 180 days after the verification date specified in the mutually agreed upon plan."

a. The GO coordinates a testing time and date with plant operations. The date depends on the real-time constraints of plant operations, and the test date is generally not known by the GO at the time that the "test plan" is submitted by the GO to the TP. As long as testing and model submittal from GO to TP meet the compliance deadlines, why does the exact test date need to be known and documented in advance? Setting the test date in advance adds no compliance benefit – it just adds an unnecessary operational burden.

Likes 0	
Dislikes 0	
Response	

James Howell - Southern Company - Southern Company Generation - 5	
Answer	No
Document Name	
Comment	

See Southern Company Comments

Likes 0	
Dislikes 0	
Response	

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	

Comment	
Similar to SRC, ERCOT is concerned with the use of “mutual agreement” within these requirements. The TP needs the authority to obtain needed information taking into account the equipment owner’s constraints. Additionally, as explained in R1, R9 appears to duplicate portions of MOD-032-1.	
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 has concerns with the “large” signal disturbances. We suggest defining large system disturbance by moving Attachment 1, Note 1 to the top in Section 6. **Reference:** See the technical rationale, Section R4 where it’s stated R4 is specific to positive sequence modeling and reflects the intent of the SAR to verify both small signal performance via staged testing (termed as validation) and large signal performance via documentation and analysis exercises.	
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; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	No
Document Name	
Comment	
R7 should be tempered by a post modification verification via testing that the update did not alter the response. The 13 month provision of MOD-032-1 could then cover any inaccuracies in the model until the time of next submittal. R8 and R9 duplicate requirements of MOD-032-1 R3 with the addition of a 90 day limit on comments from the TP, which could be handled by a modification to the MOD-032 provision.	
Likes 0	
Dislikes 0	
Response	

James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
See suggested changes from Question 2 on Requirement R1.	
Likes 0	
Dislikes 0	
Response	
Aric Root - CMS Energy - Consumers Energy Company - 4	
Answer	Yes
Document Name	
Comment	
Consumers agrees with these requirements, however, we would like the 360 days rather than the 180 calendar days of making changes to in-service equipment.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
The SDT should consider clarifying wording changes to R8. wording such as, "Each Transmission Planner shall review the verified model and accompanying information **under Requirements R2-R6,…**" may provide value-added specifity to the requirement.	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Consumers agree with these requirements; however, we would like the 360 days rather than the 180 calendar days of making changes to in-service equipment.	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Consumers agree with these requirements; however, we would like the 360 days rather than the 180 calendar days of making changes to in-service equipment.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation agrees with proposed language. 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 proposed language. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
AZPS generally supports the language in Requirements R7, R8, and R9 but supports the following EEI recommendation: “EEI does not agree the information provided in footnote #13 should be left as a footnote. Footnote #13 contains important information regarding the expectations of changes to equipment that alter resource response characteristic, therefore this information should be contained in the body of the standard not a footnote.”	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
OK	
Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
First sentence of R8 should indicate the specific verified model that is to be reviewed (under which requirement).	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
See suggested changes from Question 2 on Requirement R1.	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 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 Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
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	
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. - 3,5,6 - RF	
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

Israel Perez - Israel Perez On Behalf of: Pam Syrjala, Salt River Project, 5, 3, 1, 6; Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 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	

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

Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	

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	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	
Document Name	

Comment
National Grid supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment
Texas RE recommends including 2.3, 3.3, 4.3, and 5.3 in Requirement R7 so a change in Protection System response is captured in the updated verified model.

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
The ITC Standards Under Development Team has received no response to submit from the Standard Owners

Likes 0	
Dislikes 0	

Response

7. The SDT believes the language of MOD-026-2 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

Jack Stamper - Clark Public Utilities - 3	
Answer	No
Document Name	
Comment	

No. As I stated above, the SAR indicates that voltage control behavior during large disturbance conditions is not verified. That is not so. PRC-024 requires generators to meet region-specific voltage and frequency ride through requirements and to provide the settings for it voltaage and frequecy protection to Transmission Planners. In addition, PRC-006 requires the provision of UFLS tripping data that includes generator frequecy ride through trip settings. Adding these to MOD-026 does nothing more than make Generator Owners prove compliance with multiple standards for the same action. This is not in accordance witht the efficiency goals of the NERC Standards development which included consolidation identical actions in multiple standards into a single standard to avoid unnecessary duplication of efforts.

The addition of the protection system modeling data to MOD-026 increases the efforts (and cost) of providing protection system performance characteristices by including the requirements in multiple standards. This is not efficient or cost effective.

Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	

By their inherent nature, GOs do not belong in the transmission planning process. GOs should not have the assigned model development and validation responsibility for an ever-increasing growth of scope in the transmission planning process. Therefore, it is not cost-effective for a GO to function in a transmission planning role to perform model parameterization checks, usability, initialization, and interoperability assessments. This is effectively passing some of the cost of transmission planning to the Generator Owners, and the proposed models have not been shown to improve reliability.

MOD-026 & -027 originated from a simple but costly need to validate dynamic models of generators, exciters, and governors. The activity was important due to the uncertainty of accurate models for the dynamic response of excitation controls and governors, which was manifested in high profile blackouts in WECC during the 1990s. At the time, all controls were analog with less predictable performance characteristics and less certainty. Nowadays, with microprocessor-based controls and PRC-005 maintenance practices in place for GOs, there is little justification to mandate field-verified models of excitation control limiters, frequency controls, or Protection System elements if the technical basis for requiring PRC-019, -024, -025, -026 were correct. We are not aware of identified reliability gaps or quantified improvements in reliability to justify the scope growth of R2 and R3; this was not the reason for the SAR to initiate a standard revision.

Likes 0	

Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
See the previous comments regarding the minimum modeling requirements.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
By their inherent nature, GOs do not belong in the transmission planning process. GOs should not have the assigned model development and validation responsibility for an ever-increasing growth of scope in the transmission planning process. Therefore, it is not cost-effective for a GO to function in a transmission planning role to perform model parameterization checks, usability, initialization, and interoperability assessments. This is effectively passing some of the cost of transmission planning to the Generator Owners, and the proposed models have not been shown to improve reliability. MOD-026 & -027 originated from a simple but costly need to validate dynamic models of generators, exciters, and governors. The activity was important due to the uncertainty of accurate models for the dynamic response of excitation controls and governors, which was manifested in high profile blackouts in WECC during the 1990s. At the time, all controls were analog with less predictable performance characteristics and less certainty. Nowadays, with microprocessor-based controls and PRC-005 maintenance practices in place for GOs, there is little justification to mandate field-verified models of excitation control limiters, frequency controls, or Protection System elements if the technical basis for requiring PRC-019, -024, -025, -026 were correct. We are not aware of identified reliability gaps or quantified improvements in reliability to justify the scope growth of R2 and R3; this was not the reason for the SAR to initiate a standard revision.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	

Comment	
Properly populated generic positive sequence models for IBRs can accurately represent the equipment sufficiently for studies. The cases mentioned in the SAR were a result of improper parameters in those models. Requiring EMT models and simulations will add significant costs to GOs when the focus should be on properly verifying existing ones. While EMT and positive sequence models are useful for their specific studies (e.g., EMT is mainly used for insulation coordination, switching surge, SSR, TRV, higher-frequency control interactions, series capacitor design studies, etc.), when comparing the models one has to be aware of the differences of the two domains and the limitations of such comparisons. Transmission planners can't study the entire system with EMT models and should only be required if Transmission provides justification for them on a case-by-case basis.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Clarification toward our comments will determine cost effectiveness	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
Clarification toward our comments will determine cost effectiveness	
Likes 0	
Dislikes 0	

Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	

The new standard addresses the needs of inverter-based resources, however, the need for EMT models in addition to positive sequence models would add significant cost and time to model verification. The reason for EMT models described in the technical rationale was to address unbalanced faults which was not a need described in the SAR.

Sub-Synchronous Resonance and unbalanced faults affect traditional generation as well. Even though EMT modeling has been available for decades, it has not been required to develop these models or provide them to any entity for traditional resources. Since most utilities do not currently model generation resources with an EMT program, it would require significant investment in personnel, training, or consulting services to prepare and validate EMT models. The proposed standard does not adequately justify this expense. R4 and R5 should be more than adequate for modeling IBRs accurately for transmission planning purposes.

Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	
Answer	No
Document Name	
Comment	

Constellation relies on third party contractors for the completion of MOD-026-1 and MOD-027-1 models due to this lack of expertise and modeling software. The addition of expanded modeling requirements will increase the scope and likely the cost of analysis being completed, as there is limited experts in the industry.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	

Comment	
Constellation relies on third party contractors for the completion of MOD-026-1 and MOD-027-1 models due to this lack of expertise and modeling software. The addition of expanded modeling requirements will increase the scope and likely the cost of analysis being completed, as there is limited experts in the industry. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Derek Brown, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy contends that their will be costs associated with procurring the software required to perform EMT model studies, train employees who do not posses the skills required to perform EMT models, and develop the processes necessary to ensure compliance with the various modeling requirements when using EMT models. Evergy estimates those costs will be at least $100,000.	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
Consumers Energy believes there needs to be a technical attachment added to this requirement clarifying expectations. Also, this SAR is a little open-ended, this may give entities different outcomes.	
Likes 0	
Dislikes 0	
Response	

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
The proposed modifications to the Standard will cause Generator Owners to perform a high increase in model revisions and incur a dramatic increase in costs that outweigh any potential benefit to BES reliability.	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	No
Document Name	
Comment	
Consumers Energy believes there needs to be a technical attachment added to this requirement clarifying expectations. Also, this SAR is a little open-ended, this may give entities different outcomes.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP does not agree the language of MOD-026-2 addresses the issues outlined in the two SARs in a cost effective manner. The proposed revisions would result in the Generator Owner of synchronous units incurring significant, additional costs to model protection functions.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Pam Syrjala, Salt River Project, 5, 3, 1, 6; Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
The addition of EMT models would add significant cost and time to get everyone trained and be able to maintain these models. The additional implementation timeframe of 48 months for R2-R6 does not make it more cost effective, but it helps distribute the additional upfront costs.	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
Cost impact is not clear. Reference comments to other questions.	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3	

Answer	No
Document Name	
Comment	
Concern about cost for 2 year implementation of EMT models.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes this version of the standard puts a substantial burden on the industry to find contractors to do a complete overhaul of testing and is not cost effective to meet the standards. The proposed standard does not take into effect the current life cycle of the existing standards. There is very limited expertise available for the EMT models on the Generator Owner and Transmission Planner sides which also creates a burden.	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
The changes to MOD-026-2 to require GO/TOs to have validated models to provide to the TP is not consistent with the proposed SARs. The EMT modeling requirements is not mention in either SAR and implementation would not be cost effective.	
Likes 0	
Dislikes 0	
Response	
Aric Root - CMS Energy - Consumers Energy Company - 4	

Answer	No
Document Name	
Comment	

Consumers Energy believes there needs to be a technical attachment added to this requirement clarifying expectations. Also, this SAR is a little open-ended, this may give entities different outcomes.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

There is a significant amount of data that is being required that may not be used by the TP or is already covered in another Standard. This would not be cost effective. We need to provide only the data that is and not duplicated in another Standard.

Likes 0	
Dislikes 0	
Response	

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer	No
Document Name	
Comment	

As a Registered Entity that currently does not have software to create and maintain EMT models, it will have to be purchased. Additionally, personnel will need time to develop expertise with EMT models.

Currently, WECC has an EMT Task Force in place to provide guidance to their members on EMT models. Registered Entities need all Regional Entities to provide some similar support by creating EMT Task Force. This allows entities to learn from the expertises of others and helps ensure that data from the models can be shared.

Likes 0	
Dislikes 0	
Response	

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
It would be more cost effective if the Transmission Planners were to validate the EMT models with a simpler, controllable infinite bus test rather than validating through a full EMT case. However, if the individual Transmission Planners were assigned the responsibility of performing the EMT analysis on the full EMT case (*i.e.*, for initialization test, interoperability test, and field validation test) going forward, the Transmission Planners would accrue significant costs for training, software, and labor hours.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon recommends the SDT conduct a field test to determine the spedific circumstances that benefit from utilizing EMT models. Submitted on behalf of Exelon, Segments 1 & 3	
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 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	
At this time, PG&E cannot make a determination if the modifications to MOD-026-2 are cost effective.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	No
Document Name	
Comment	
The SRC has the following concerns: It appears there is potential for additional units (e.g. 20 MW – 100 MW) required to submit models in the two year window may be coincident with the existing units 10 year clock. The timing for the newly added units must be different than the 10 year date to prevent a potential doubling of year 10 work. This is estimated to have an overall MOD-026 scope increase by 59%, with an approximately 50% of original scope scheduled for year 10. If the new facilities must submit by year 10 of the first phase, it is anticipated to double the expected models needing to be processed in that year-10 time frame.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	No
Document Name	
Comment	

Most registered entities do not currently have the expertise, experience or software to work with the EMT models required by MOD-026-2. The lack of industry knowledge on EMT modeling and studies will take some time to correct. Registered entities will have to pay for the software and additional training to educate their engineers on EMT principles.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	No
Document Name	
Comment	
CPS Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports the comments submitted by LPPC.	
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; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	No
Document Name	

Comment	
The language of MOD-026-2 largely duplicates validation and model data distribution requirements of MOD-032-1 without providing needed guidance for model verification tests. Root causes of prior IBR tripping events are not addressed by this approach, and leave the industry without a benchmark for IBR model verification that improves BES event outcomes.	
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	
Most existing facilities do not have high speed digital fault recorder technology probably at both the generator low side and high side busses for recording the signals required by R6.4 to model a facility. There are many current, voltage, and control signals to monitor to verify something as complex as an EMT model. Applying the requirement for EMT models at TP/PC selected location for facilities built and commissioned after the reatification of this standard revision needs to be the starting point for applicabililty so that facilities can be specified, engineered, and designed to provide the best ride through characteristics and so that EMT models can be provided with the equipment. Retroactive application to existing facilities will be very costly and has not proven to provide accurate predictions of equipment response to varying types of large system disturbances. Southern Company believes that a better use of engineering resources and financial resourses is to apply thie changes proposed in this standard revision to future equipmient rather than to existing equipment.	
Likes 0	
Dislikes 0	
Response	

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	
Comment	
If the issues we've pointed out regarding EMT model verification are addressed, then yes we believe the draft is generally cost effective and addresses the issues in the SARs. However, we feel there is still work to be done on the language and logistics of multiple requirements.	
Likes 0	
Dislikes 0	

Response	
James Howell - Southern Company - Southern Company Generation - 5	
Answer	No
Document Name	
Comment	
See Southern Company Comments	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
SPP suggests the drafting team take a deeper dive into this cost effort. There are a lot of factors that need to be considered which should be discussed. For example, the cost impact on purchasing the appropriate software to conduct the SCR screenings as well as the EMT studies, including the cost for training with manufacturing entities like EPRI and SIEMENs, as well as the expectation on identifying reliability risks on the grid.	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	
Combining MOD-026-1 and MOD-027-1 into a single Standard will result in significant administrative costs and time for entities with a well established compliance program for these standards. Many work hours from engineers or consultants, and other staff will be required to modify all of the compliance processes already established.	
Likes 0	
Dislikes 0	

Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
Agree with comments submitted by BPA.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
The MRO NSRF is in agreement from a Generator Owner standpoint, so long as the implementation plan maintains the following statement, “Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 within the periodic timeframes of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2).” The MRO NSRF cannot comment on the cost effectiveness of developing an EMT model, please see response to question 8, as its members and guest have little to no experience with EMT model development.	

Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MidAmerican supports MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
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	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Dwanique Spiller, Berkshire Hathaway - NV Energy, 5; - Berkshire Hathaway - NV Energy - 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 Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
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	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
Unsure	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	

Black Hills Corporation is unable to determine if this will or will not be cost effective.

Likes 0	
Dislikes 0	
Response	
David Jendras - 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	
The ITC Standards Under Development Team has received no response to submit from the Standard Owners	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	
Document Name	
Comment	
N/A	

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

The NERC Standard Processes Manual (Version 4, dated March 1, 2019) outlines a process for conducting field tests (Section 6.0) to help a drafting team “analyze data and validate concepts in the development of Reliability Standards”. It seems this process is rarely if ever used in developing NERC standards. In the case of the proposed MOD-026-2, we believe a properly designed field test could help inform the drafting team of any potential issues in implementing the draft requirements and also provide further insights on cost effectiveness.

Likes 0	
Dislikes 0	

Response

8. The SDT proposes a 1 year implementation plan for Requirements R1, R7, R8, and R9, with an additional 2 years for compliance with Requirements R2-R6 for newly applicable Facilities. For existing Facilities, the Implementation Plan proposes the ten year reoccurring periodicity is maintained from the date of previous model verification. 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.

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

Answer	No
Document Name	

Comment

LPPC recommends that the implementation period for R6 be extended to 48 months to allow Registered Entities time to purchase EMT software and develop expertise with EMT modeling and studies. Additional time will be required to ensure that models used by registered entities are compatible with the models used by their regions and different software vendors.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis

Answer	No
Document Name	

Comment

The SRC proposes the following Implementation Plan: As identified in in response to Question 7, if all remaining generators under the current 10 year plan must submit in 2026 and the timing of this MOD-026-2 is also anticipating R2-R6 new units (e.g. 20-100MW and aggregate >75 MW and HVDC and Dynamic reactive), then the scope for 2026 may more than double for some TPs As a result, the SRC has concerns with a 3-year implementation for EMT models. Industry will need time to develop EMT models, train personnel and hire consultants. There are a limited number of existing consultants and personnel that have the expertise to develop such models. The SRC proposes the additional time frame allowed to comply with R2-R6 be extended to four (4) years, for a total of five (5) years.

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 agrees with the comments provided by EEI on not supporting the additional two (2) year compliance requirement for EMT due to the lack of tools and skills to develop the models. As noted by EEI, the SDT should change the two (2) year time to four (4) years to better ensure the industry has the skills, tools, training, and experience required by the modifications.

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 has concerns about the implementation period for required EMT models being too short. We recommend a 5-year implementation process due to the human, data, training, computer resources, and vendor development processes. Further explanation of these reasons follows:

1. EMT models are complex, and it will take 5-years to train personnel and develop EMT models.

2. There are a limited number of consultants available to develop EMT models. A 2-year implementation process will cause a bottleneck on available resources.

3. EMT models require data that positive sequence dynamics models do not. Additional new data on new systems must be gathered first to then model. This will take time.

4. Entities will need time to identify and purchase new software for EMT models.

5. An EMT simulation for something like a NERC Odessa event will require a lot of computer power.

6. Industry will need time to develop model conversion software, something like CAPE to EMT model conversions to ease the labor issue, speed model development and keep model accuracy to acceptable levels

7. Vendors might not be able to provide required EMT inverter models as specifically requested by the planning authority.

The NAGF suggests removing the 90-day, 180-day, and 365-day arbitrary deadlines and replacing with the joint PA / TP model building process. Many PA and TP's build models approximately annually. Shorter deadlines measured in days are not useful or efficient, rather they become administrative compliance burdens and should all be eliminated.

Likes 0	
Dislikes 0	

Response	
Michael Dillard - Austin Energy - 5	
Answer	No
Document Name	
Comment	
City of Austin dba Austin Energy agrees with LPPC's recommendation that the implementation period for R6 be extended to 48 months to allow Registered Entities time to purchase EMT software and develop expertise with EMT modeling and studies. Additional time will be required to ensure that models used by Registered Entities are compatible with the models used by their regions and different software vendors.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	No
Document Name	
Comment	
The applicability in MOD-026-02 now refers to "Inclusion I2 of the BES definition", which is: Gross individual nameplate rating greater than 20 MVA. Or, Gross plant/facility aggregate nameplate rating greater than 75 MVA. This change in the applicability criteria will have a major impact on the number of applicable units (> 50 units). Additional time is needed for R2-R6 compliance for newly applicable Facilities. Proposed alternate implementation plan is to include a 30% partial compliance 3 years after the effective date of the applicable governmental authority's order approving the MOD-26-01, 50% partial compliance 2 years after the 30% compliance, and 100% compliance 4 years after the 50% compliance. Note: The version of the "BES definition", that is mentioned at section 4.2 of MOD-026-02, should be clearly stated in MOD-026-02, to avoid any misunderstanding to the applicability criteria.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No

Document Name	
Comment	

MidAmerican supports MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1

Answer	No
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI for Question #8.

Submitted on behalf of Exelon, Segments 1 & 3

Likes 0	
Dislikes 0	
Response	

George Brown - Acciona Energy North America - 5

Answer	No
Document Name	
Comment	

Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.

Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO

Answer	No
Document Name	

Comment	
The MRO NSRF has concerns for the 3 year implementation of EMT models. Industry will need time to train personnel, hire consultants and develop EMT models. There are a limited number of consultants and personnel that can develop such models. The MRO NSRF recommends a 5 year staged implementation.	
Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy supports the comments as submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Oncor recommends that the duration of the implementation plan timeline be extended to 2 years for R1, R7, R8, and R9 to provide adequate time for the Transmission Planners and Planning Authorities to establish their internal processes related to the update.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	

Comment	
Recommend that the implementation period for R6 be extended to 48 months to allow Registered Entities time to purchase EMT software and develop expertise with EMT modeling.	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
We could comply with the dynamic modeling as proposed within the implementation period, however we could not provide the EMT modeling within the proposed implemnation plan. It would be difficult to provide an alternate estimate timeframe for the EMT requirements since we currently do not have any modeling and would require further guidance from NERC.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment

If a GO's testing is due within two years, the GO would then also need to include the EMT models, which isn't feasible. BPA believes that more time may be needed to better understand the EMT models from the GO and TP perspective as well.

EMT – BPA does not feel that EMT should be a priority, as it is categorically buredensome. BPA does not believe this requirement is needed. The timeline is not practical, BPA believes the EMT requirement is not achievable by the industry within this timeframe.

Likes 0

Dislikes 0

Response

Christine Kane - WEC Energy Group, Inc. - 3

Answer	No
Document Name	

Comment

Agree with 1 year implementation period for R1, R7, R8 and R9. Would like 4 years for R2-6.

Likes 0

Dislikes 0

Response

Israel Perez - Israel Perez On Behalf of: Pam Syrjala, Salt River Project, 5, 3, 1, 6; Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez

Answer	No
Document Name	

Comment

We support other entities sentiment that 24 months is not sufficient for EMT models. As such, we agree with others that 48 months is more appropriate for R2-R6, rather than the 24 months currently spelled out in the implementation plan.

Likes 0

Dislikes 0

Response

Thomas Foltz - AEP - 5

Answer	No

Document Name	
Comment	
AEP believes the proposed Implementation Plan is too aggressive and would not allow entities to accomplish all the proposed changes within its wider scope. In addition, all Generator Owners would be competing with the same group of third party consultants that specialize in performing model verification, leading to additional impacts and challenges in achieving compliance. Rather than allowing only two additional years for compliance with R2-R6, we suggest allowing three or four additional years.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Dwanique Spiller, Berkshire Hathaway - NV Energy, 5; - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
The proposed implementation plan is reasonable with the exception of the requirements related to EMT models. NV Energy does not have the experience, knowledge, or tools required to create requirements and processes to determine acceptable EMT models. NV Energy proposes that an implementation timeline of at least 2 years for R1.3 should be used to procure software capable of analyzing EMT models and proper training to ensure that the models are being analyzed correctly.	
Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports EEI's comment.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	

Answer	No
Document Name	
Comment	

Dominion Energy does not agree that the 2-year implementation plan for Requirements R2-R6 is adequate. The expansion of the applicable unit criteria will bring a large number of our existing facilities which previously were not in scope within scope of MOD-026-2, many of which are solar facilities requiring additional EMT model verifications under Requirement R6. With the limited number of engineering firms capable of model development and verification, as well as the continued model reverifications for changes under Requirement R7 and initial verifications for new applicable units during the implementation period, it will be a challenge to meet the 2-year compliance deadline.

Dominion Energy proposes either an extension to the implementation plan to at least 3 years or a phased-in implementation plan, similar to MOD-026-1 and MOD-027-1, over at least a 3-year period to allow for the planning, scheduling, testing, and model development of the additional in-scope facilities.

Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Derek Brown, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster

Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) to question #8.

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 additional 2 year compliance requirement for EMT models. The skills and tools necessary to develop these models are only now being developed within most companies and while we recognize that some areas have a need to become quickly proficient, this is not reflective of all areas or regions. Moreover, compulsory compliance within 2 years of the effective date of this standard is too aggressive, even in those areas with higher needs, and does not provide those entities with the latitude to develop the necessary skills that will, over time, be beneficial learnings for the rest of the industry. For these reasons, the SDT should modify the 2 year compliance requirement for EMT models to 4 years. This will better ensure the industry has the skills, tools, training and experience needed to meet this challenging goal as the resource mix grows and expands its dependance on

IBRs.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment

Comments: EEI does not support the additional 2 year compliance requirement for EMT models. The skills and tools necessary to develop these models are only now being developed within most companies and while we recognize that some areas have a need to become quickly proficient, this is not reflective of all areas or regions. Moreover, compulsory compliance within 2 years of the effective date of this standard is too aggressive, even in those areas with higher needs, and does not provide those entities with the latitude to develop the necessary skills that will, over time, be beneficial learnings for the rest of the industry. For these reasons, the SDT should modify the 2 year compliance requirement for EMT models to 4 years. This will better ensure the industry has the skills, tools, training and experience needed to meet this challenging goal as the resource mix grows and expands its dependance on IBRs.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation requests the consideration to allow excitation and governor modeling to be done separately and not in conjunction, as completing modeling's together at the next interval cycle would short cycle models completed under the original implementation plan. As models were planned and executed separately throughout the periodic implementation.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation requests the consideration to allow excitation and governor modeling to be done separately and not in conjunction, as completing modeling's together at the next interval cycle would short cycle models completed under the original implementation plan. As models were planned and executed separately throughout the periodic implementation. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS agrees with the implementation plan if the recommendation to remove the required use of EMT models is accepted. If it is not removed, AZPS supports the following comment submitted by EEI: “EEI does not support the additional 2 year compliance requirement for EMT models. The skills and tools necessary to develop these models are only now being developed within most companies and while we recognize that some areas have a need to become quickly proficient, this is not reflective of all areas or regions. Moreover, compulsory compliance within 2 years of the effective date of this standard is too aggressive, even in those areas with higher needs, and does not provide those entities with the latitude to develop the necessary skills that will, over time, be beneficial learnings for the rest of the industry. For these reasons, the SDT should modify the 2 year compliance requirement for EMT models to 4 years. This will better ensure the industry has the skills, tools, training and experience needed to meet this challenging goal as the resource mix grows and expands its dependance on IBRs.”	
Likes 0	
Dislikes 0	
Response	

Isidoro Behar - Long Island Power Authority - 1	
Answer	No
Document Name	

Comment	

It is recommended that the implementation plan and compliance dates for R4 and R6 for existing “FACTS devices per Section 4.2.4.2”, which are being affected by these modeling requirements for the first time, be clarified. It is not clear if the compliance date is 2 years or 10 years.

Specifically for Requirements 4 and 6 –

The Implementation plan states that “Applicable Entities shall not be required to comply with Requirement R2, R3, R4, R5, and R6 until twenty-four (24) months after the effective date of Reliability Standard MOD-026-2.”

For existing “FACTS devices per Section 4.2.4.2”, which are being affected by these modeling requirements for the first time, it is interpreted that the compliance date for R4 and R6 is twenty-four months after the effective date of Reliability Standard MOD-026-2. If this interpretation is correct, then this implementation plan timeframe is deemed to be too short.

It is likely that many Transmission Owners (TOs) that own rely on the services of the nonsynchronous resource (i.e. FACTS, HVDC) vendor / OEM for model development, verficiation and validation – due to the specialized nature of these resources. The proposed MOD-026-2 would likely increase a TO’s reliance on support services from their nonsynchronous resource vendors / OEMs. This increased reliance on specific OEMs across the continent may lead to much longer lead times for OEM support services related to model development, benchmarking and verification. Such OEM longer lead times may put TO compliance obligations in jeopardy.

As an alternative, for existing “FACTS devices per Section 4.2.4.2” which are being affected by these modeling requirements for the first time, it is recommended that the compliance date for R4 and R6 be at least forty-eight months after the effective date of Reliability Standard MOD-026-2.

It is recommended that the drafting team consider working with industry vendors / OEMs of transmission connected nonsynchronous sources (i.e. FACTS, HVDC) to see from their perpsective if the stated implementation plan / compliance dates are feasible.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

FE agrees with EEI’s comments:

EEI does not support the additional 2 year compliance requirement for EMT models. The skills and tools necessary to develop these models are only now being developed within most companies and while we recognize that some areas have a need to become quickly proficient, this is not reflective of all areas or regions. Moreover, compulsory compliance within 2 years of the effective date of this standard is too aggressive, even in those areas with higher needs, and does not provide those entities with the latitude to develop the necessary skills that will, over time, be beneficial learnings for the rest of the industry. For these reasons, the SDT should modify the 2 year compliance requirement for EMT models to 4 years. This will better ensure the industry has the skills, tools, training and experience needed to meet this challenging goal as the resource mix grows and expands its dependance on IBRs.

Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy suggest a 5-year implementation plan for R2-6 and a 2-year implementation for R1, R7, R8, and R9. This period is needed because NERC auditors require GOs to put program documents, procedures, test plans, work orders, etc., in place. Duke Energy will require time to make these changes and considers the suggested timeframe to restrictive.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
With such major changes the Implementation plan should be increased by at least 4 years.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
At least 4 years will be required for retesting planning.	
Likes 0	

Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
At least 4 years will be required for retesting planning.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends the new R1 model requirements and processes be developed and made available to Generator Owners and Transmission Owners within 24 months following regulatory approval. For newly applicable Facilities, Reclamation recommends an additional 24 months after the new model requirements and processes are received to complete the models of the applicable units. For existing applicable Facilities, Reclamation recommends requirements R2 through R9 have a 10-year implementation plan for all Facilities to maintain continuity with entities' existing modeling schedules under the current versions of MOD-025, MOD-026, and MOD-027.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
EEI does not support the additional 2 year compliance requirement for EMT models. The skills and tools necessary to develop these models are only now being developed within most companies and while we recognize that some areas have a need to become quickly proficient, this is not reflective of all areas or regions. Moreover, compulsory compliance within 2 years of the effective date of this standard is too aggressive, even in those areas with	

higher needs, and does not provide those entities with the latitude to develop the necessary skills that will, over time, be beneficial learnings for the rest of the industry. For these reasons, the SDT should modify the 2 year compliance requirement for EMT models to 4 years. This will better ensure the industry has the skills, tools, training and experience needed to meet this challenging goal as the resource mix grows and expands its dependance on IBRs.

Likes 0	
Dislikes 0	

Response

Russell Noble - Cowlitz County PUD - 3

Answer	No
Document Name	

Comment

Agree with comments submitted by BPA.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Lowering the Facility applicability from individual units greater than 100 MVA (Eastern Interconnection) to 20 MVA (resource identified through Inclusion I2 of the BES definition) could add a significant number of newly applicable Facilities requiring verifications within two years of having the TP's "dynamic model requirements and processes" available. While "grandfathered" existing units previously verified under MOD-026-1 and MOD-027-1 are allowed to stay on a 10-year schedule, there are "triggers" in Attachment 1 that can advance the due date / shorten this interval. Would the asset owner comply with the MOD-026-1 and MOD-027-1 triggers until the 10-year anniversary is reached and then transition to MOD-026-2, or would a "trigger" from MOD-026-2 Attachment 1 (E.g. Row 4, Row 5, Row 10) result in an early (prior to the 10-year anniversary) transition to MOD-026-2? For GOs that own a lot of applicable units, with some being subject to the current standards and others that will be added under the proposed new standard, this will become an even greater administrative challenge. We suggest a longer implementation period be allowed for existing units that are newly applicable (5-years), and that the implementation plan be revised to further clarify the transition period for existing units that are on a 10-year cycle but may experience a trigger as described in Attachment 1 before their 10-year anniversary.

Likes 0	
Dislikes 0	

Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID agrees with the general purpose of the standard. However, IID would like to see an extension to the timeline for R6 implementation to allow and encourage more participation to the regional task forces (EMTTF).	
Likes 0	
Dislikes 0	
Response	
James Howell - Southern Company - Southern Company Generation - 5	
Answer	No
Document Name	
Comment	
See Southern Company 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 has concerns about the implementation period for required EMT models being too short. We recommend a 5-year implementation process due to the human, data, training, computer resources, and vendor development processes. Further explanation of these reasons follows:

- EMT models are complex, and it will take 5-years to train personnel and develop EMT models.
- There are a limited number of consultants available to develop EMT models. A 2-year implementation process will cause a bottleneck on available resources.

- EMT models require data that positive sequence dynamics models do not. Additional new data on new systems must be gathered first to then model. This will take time.
- Entities will need time to identify and purchase new software for EMT models.
- An EMT simulation for something like a NERC Odessa event will require a lot of computer power.
- Industry will need time to develop model conversion software, something like CAPE to EMT model conversions to ease the labor issue, speed model development and keep model accuracy to acceptable levels
- Vendors might not be able to provide required EMT inverter models as specifically requested by the planning authority.

Southern Company believes that any existing unit newly brought into the scope of this standard for modeling needs to have a new “10 year implementation plan”, just like version 1 of MOD-026 and -027. It must be realized that the original 10 year modeling effort repeats, and the entities charged with this work, again, need to be permitted to control the schedule so that it can be levelized over time and not overloaded in one small section of the 10 year cycle. This makes the ability to comply much more achievable.

Southern Company agrees with EEI’s comments on this item: the proposed implantation plan is too short.

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; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ

Answer	No
Document Name	

Comment

The implementation timeframe for new facilities appears adequate, but existing facilities should be addressed in a three year timeframe given the increased frequency of IBR disturbances that have demonstrated fragility of present modeling and commissioning approaches for the existing IBR fleet.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power supports the comments submitted by LPPC.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aric Root - CMS Energy - Consumers Energy Company - 4	
Answer	Yes
Document Name	
Comment	
Consumers Energy is fine with this implementation plan time frame.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
• Portland General Electric supports EEI comments for extension of the compliance requirement for EMT models to four years.	

- We do agree with the implementation plan's *Initial Performance of Periodic Requirements* and in particular language around when a periodic model verification date falls between the effective date of MOD-026-2 and the Compliance Date.

Likes 0	
Dislikes 0	

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer	Yes
Document Name	

Comment

Consumers Energy is fine with this implementation plan time frame.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes
Document Name	

Comment

Consumers Energy is fine with this implementation plan time frame.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	Yes
Document Name	

Comment

No Comments

Likes 0	

Dislikes 0	
Response	
Jack Stamper - Clark Public Utilities - 3	
Answer	Yes
Document Name	
Comment	
I agree with this. My utility only has one applicable generaton and is planning on completing its existing MOD-026-1 and MOD-026-2 modeling update in June, 2022. I believe it would be ineficient to require compliance with any new modeling requirements of MOD-026-2 until the new ten year time period has elapsed in 2032.	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Baldwin - Lower Colorado River Authority - 1	
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 Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2	
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	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	

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	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
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	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
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	
Glenn Pressler - CPS Energy - 3	

Answer	
Document Name	
Comment	
(N/A). CPS Energy believes more time is needed for industry to catch up, for both modeling efficiencies and SME expertise; up to 4-years is needed.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
no comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	
National Grid supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment

Texas RE understands the Implementation Plan as follows:

{C}·	{C}The first bookend for the 10-year verification occurs during the implementation of MOD-026-1 and MOD-027-1. This could potentially be anytime between July 1, 2014 and July 1, 2024.

{C}·	{C}The second verification would need to occur 10 years after the first verification, which was done in the time between July 1, 2014 and July 1, 2024 or the Compliance Date for R2-R6, whichever is later.

Regarding this sentence: “When the periodic timeframe falls between the effective date of MOD-026-2 and the Compliance Date for the respective requirement, the Applicable Entity shall comply with the Requirement(s) of MOD-026-2 by the Compliance Date.” Texas RE understands this to mean, in the case where MOD-026-2 is approved on 10/15/2022 making the Effective Date 1/1/2023 and the Compliance Date 1/1/2025, the following:

Scenario 1: The verification occurred on 7/1/2016, making the second verification due by 7/1/2026. In this scenario, the entity would have to do its second verification by 7/1/2026, since the due date is after the Compliance Date.

Scenario 2: The verification occurred on 8/1/2014, making the second verification due 8/1/2024. In this scenario, entity would have until 1/1/2025 to do the second verification, since the due date is between the effective date of MOD-026-2 and the Compliance Date.

Is this the intent of the SDT’s language in the implementation plan?

Additionally, Texas RE noticed that the Implementation Plan uses the term Applicable Entities. Since the term is capitalized, it seems as though it should be defined somewhere. It is not in the NERC Glossary, nor is it defined in the standard. Is it intended that Applicable Entities are the Functional Entities described in section A. 4?

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	

No Comment

Likes 0	
Dislikes 0	

Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI agrees with EEI's comments: EEI does not support the additional 2 year compliance requirement for EMT models. The skills and tools necessary to develop these models are only now being developed within most companies and while we recognize that some areas have a need to become quickly proficient, this is not reflective of all areas or regions. Moreover, compulsory compliance within 2 years of the effective date of this standard is too aggressive, even in those areas with higher needs, and does not provide those entities with the latitude to develop the necessary skills that will, over time, be beneficial learnings for the rest of the industry. For these reasons, the SDT should modify the 2 year compliance requirement for EMT models to 4 years. This will better ensure the industry has the skills, tools, training and experience needed to meet this challenging goal as the resource mix grows and expands its dependance on IBRs.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	
Document Name	
Comment	
N/A	
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	

The ITC Standards Under Development Team has received no response to submit from the Standard Owners	
Likes 0	
Dislikes 0	
Response	

9. Provide any additional comments on the standard and technical rationale document for the SDT to consider, if desired.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	
Document Name	
Comment	

Proposed change to Facilities Section to more clearly align with the approved BES Definition (see below):

4.2. Facilities: For the purpose of this standard, the term "applicable units" shall mean any one of the following:

4.2.1 Individual generating resource **meeting the unit criteria set by identified through** Inclusion I2 of the BES definition.

4.2.2 Generating plant/Facility **meeting the plant/Facility criteria set by identified through** Inclusion I2 of the BES definition.

4.2.3 **Generating plant/Facility of dDispersed** power producing resources **that aggregate to a total capacity set by identified through** Inclusion I4 of the BES definition.

4.2.4 Dynamic reactive resources **identified through meeting the criteria set by** Inclusion I5 of the BES definition with a gross nameplate rating greater than 20 MVAr, **or an aggregated site rating greater than 20 MVAr,** including, but not limited to:

4.2.4.1 Synchronous condenser; and

4.2.4.2 Flexible alternating current transmission system (FACTS) devices.

4.2.5 HVDC terminal equipment including:

4.2.5.1 Line commutated converter (LCC); and

4.2.5.2 Voltage source converter (VSC

Attachment 1 (Model Verification Periodicity) Comment

EEI suggests the following changes to Row 11, noting that OEMs are under no specific obligation to provide the models identified in MOD-026-2, unless such a requirement was written into the contract at the time the resource was purchased.

Verification Conditions:

Commissioning date of the Facility is before January 1, 2015;

OR

OEM is no longer in business; OR

OEM no longer supports model(s) for in-service equipment at

the Facility**; OR**

OEM is unwilling (or otherwise unable) to provide the supporting model (s) for in-service equipment at the Facility.

(Requirement R6 exemption

Throughout MOD-026-2 it uses the legacy title of Planning Authority. EEI suggests that the wherever this term is used, it be replaced with the preferred term “Planning Coordinator.

Section C “Compliance”

EEI asks the SDT to use the most up-to-date language in this section.

Section E “Associated Documents”

EEI asks the SDT to add the Implementation Plan and Technical Rationale to this section.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	
Document Name	

Comment

No Comments

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	

Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
There is a lack of published assessment on the effectiveness of transmission planning resulting from the implementation of the current versions of MOD-026-1 and MOD-027-1. Without these assessments, proposed additions to MOD-026-2 appear like a wish list of nice-to-have features, rather than necessary additions with quantified justification. Further requirements should be added only when tangible reliability gaps are identified. Before proposing new standard requirements, more fully developed technical foundation documents are needed.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	
Document Name	
Comment	
There is a lack of published assessment on the effectiveness of transmission planning resulting from the implementation of the current versions of the MOD-026-1 and MOD-027-1. Without these assessments, proposed additions to MOD-026-2 appear like a wish list of nice-to-have features, rather than necessary additions with quantified justification. Further requirements should be added only when tangible, reliability gaps are identified. Before proposing new standard requirements, more fully developed technical foundation documents are needed.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	

Answer	
Document Name	
Comment	

To better align with the Standards Alignment with Registration NERC project (2017-07), Planning Authority should be replaced with Planning Coordinator in all documents related to this project (MOD-026-2, Implementation Plan, Mapping Document, VRF/VSL Justifications and Technical Rationale).

Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	

General comments:

Applicable Facilities in Section 4.2.3 criteria is changing. It proposes every interconnect align with Inclusion I2. Our previous criteria in the Eastern Interconnect was 100MVA or 100MVA station aggregate. New requirements state a 20MVA nameplate or 75MVA station aggregate. This action will add a significant cost to GOs and from our conversations with TP, the synchronous machines that will be pulled in will provide no benefit to their studies. Suggest standard maintain the existing MVA thresholds currently in MOD-026 and MOD-027.

Generation feels the timeline change in Attachment 1 rows 5 and 6 needs to remain the same as existing standards. The lack of qualified personnel, coordination of testing, and system conditions all contribute to extended submittal times.

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	

First Energy agrees with EEI's comments:

Proposed change to Facilities Section to more clearly align with the approved BES Definition (see below):

4.2. Facilities: For the purpose of this standard, the term “applicable units” shall mean any one of the following:

4.2.1 Individual generating resource **meeting the unit criteria set by** Inclusion I2 of the BES definition.

4.2.2 Generating plant/Facility **meeting the plant/Facility criteria set by** Inclusion I2 of the BES definition.

4.2.3 **Dispersed** power producing resources **that aggregate to a total capacity set by** Inclusion I4 of the BES definition.

4.2.4 Dynamic reactive resources **meeting the criteria set by** Inclusion I5 of the BES definition with a gross nameplate rating greater than 20 MVA**r**, **or an aggregated site rating greater than 20 MVAr,** including, but not limited to:

4.2.4.1 Synchronous condenser; and

4.2.4.2 Flexible alternating current transmission system (FACTS) devices.

4.2.5 HVDC terminal equipment including:

4.2.5.1 Line commutated converter (LCC); and

4.2.5.2 Voltage source converter (VSC)

Attachment 1 (Model Verification Periodicity) Comment

EEI suggests the following changes to Row 11, noting that OEMs are under no specific obligation to provide the models identified in MOD-026-2, unless such a requirement was written into the contract at the time the resource was purchased.

Verification Conditions:

Commissioning date of the Facility is before January 1, 2015;

OR

OEM is no longer in business; OR

OEM no longer supports model(s) for in-service equipment at

the Facility**; OR**

OEM is unwilling (or otherwise unable) to provide the supporting model (s) for in-service equipment at the Facility.

(Requirement R6 exemption)

Throughout MOD-026-2 it uses the legacy title of Planning Authority. EEI suggests that the wherever this term is used, it be replaced with the preferred term “Planning Coordinator.

Section C “Compliance”

EEI asks the SDT to use the most up-to-date language in this section.

Section E “Associated Documents”

EEI asks the SDT to add the Implementation Plan and Technical Rationale to this section.

Likes 0	

Dislikes 0	

Response

Isidoro Behar - Long Island Power Authority - 1

Answer	
Document Name	

Comment

In terms of dynamic simulation modeling of nonsynchronous sources (i.e. FACTS, HVDC), it is expected that such dynamic models would be developed by and provided by the device vendor. It is encouraged that the applicable standards promote the development of, and use of, standardized "off the shelf" dynamic simulation software models.

It is likely that many Transmission Owners (that own a Facility listed in Section 4.2.4 or 4.2.5) rely on the services of the nonsynchronous resource (i.e. FACTS, HVDC) vendor / OEM for model development, benchmarking and verification – due to the specialized nature of these resources. The proposed MOD-026-2 would likely increase a TO's reliance on support services from their nonsynchronous resource vendors / OEMs, with a corresponding increase in TO costs.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

AECI agrees with EEI's comments:

Proposed change to Facilities Section to more clearly align with the approved BES Definition (see below):

4.2. Facilities: For the purpose of this standard, the term "applicable units" shall mean any one of the following:

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4.2.2 Generating plant/Facility **meeting the plant/Facility criteria set by** Inclusion I2 of the BES definition.

4.2.3 **Dispersed** power producing resources **that aggregate to a total capacity set by** Inclusion I4 of the BES definition.

4.2.4 Dynamic reactive resources **meeting the criteria set by** Inclusion I5 of the BES definition with a gross nameplate rating greater than 20 MVAr, **or**

an aggregated site rating greater than 20 MVAr, including, but not limited to:

4.2.4.1 Synchronous condenser; and

4.2.4.2 Flexible alternating current transmission system (FACTS) devices.

4.2.5 HVDC terminal equipment including:

4.2.5.1 Line commutated converter (LCC); and

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Attachment 1 (Model Verification Periodicity) Comment

EEI suggests the following changes to Row 11, noting that OEMs are under no specific obligation to provide the models identified in MOD-026-2, unless such a requirement was written into the contract at the time the resource was purchased.

Verification Conditions:

Commissioning date of the Facility is before January 1, 2015;

OR

OEM is no longer in business; OR

OEM no longer supports model(s) for in-service equipment at

the Facility**; OR**

OEM is unwilling (or otherwise unable) to provide the supporting model (s) for in-service equipment at the Facility.

(Requirement R6 exemption)

Throughout MOD-026-2 it uses the legacy title of Planning Authority. EEI suggests that the wherever this term is used, it be replaced with the preferred term “Planning Coordinator.

Section C “Compliance”

EEI asks the SDT to use the most up-to-date language in this section.

Section E “Associated Documents”

EEI asks the SDT to add the Implementation Plan and Technical Rationale to this section.

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5	
Answer	
Document Name	
Comment	

Constellation requests that the SDT evaluate and clarify the language under draft MOD-026-2 Attachment 1 "Model Verification Periodicity" specifically Row 9 that gives an exemption to R3 or R5 requirement to provide a validated model (and therefore any associated testing or analysis) for any unit that meets the conditions of the Row (i.e., a written statement to the TP stating the unit meets the condition is sufficient to meet the R3 or R5 requirements). The Verification Condition stated in Row 9 has historically been interpreted by GOs in two different ways: 1. The row applies if the unit does not respond in either direction: a. Unit does not respond to over frequency events, and b. Unit does not respond to under frequency events. 2. The row applies if the unit responds in just one direction: a. Unit does not respond to an over frequency event but does respond to an under frequency event, or b. Unit does not respond to an under frequency event but does respond to an over frequency event.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	

Constellation requests that the SDT evaluate and clarify the language under draft MOD-026-2 Attachment 1 "Model Verification Periodicity" specifically Row 9 that gives an exemption to R3 or R5 requirement to provide a validated model (and therefore any associated testing or analysis) for any unit that meets the conditions of the Row (i.e., a written statement to the TP stating the unit meets the condition is sufficient to meet the R3 or R5 requirements). The Verification Condition stated in Row 9 has historically been interpreted by GOs in two different ways: 1. The row applies if the unit does not respond in either direction: a. Unit does not respond to over frequency events, and b. Unit does not respond to under frequency events. 2. The row applies if the unit responds in just one direction: a. Unit does not respond to an over frequency event but does respond to an under frequency event, or b. Unit does not respond to an under frequency event but does respond to an over frequency event.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	

Comment

ATC would like to assure our ability to collect an updated model if we observe a disturbance on the system that does not match the model response. While a version of this language is generally present in MOD-032, we believe the requirement for a GO to submit updated modeling information in response to a transmission system event should still be present in MOD-026-2. ATC would like to see the language restored to the proposed standard similar to MOD-026-1/MOD-027-1 R3 (Bullet 3) that states the GO shall provide a written response to its TP within 90 calendar days of receiving the following notice,

"Written comments and supporting evidence from its Transmission Planner indicating that the simulated (excitation control system or plant volt/var control function model)/(turbine/governor and load control or active power/frequency control) response did not match the recorded response to a transmission system event."

2. The name of the standard should be renamed to incorporate the act of validation as called out in section 6.2. Perhaps the standard can be renamed as, "MOD-026-2 – Verification and Validation of Dynamic Models and Data for BES Connected Facilities."

3. Additionally, the acts of validation and verification of models should be better explained within the standard and/or requirements. The standard defines verification and validation in section 6, but then makes validation a part of verified models as shown in R2-R6. "The verified model shall include… RX.4 validation of…". There should be verification of models before changes or resource interconnection, then validation some time shortly after the change. In other words, there should be discussion within the standard of verified models separately from validated models and using a "verified and validated" term to tie the processes together at the end of validation. Both verification and validation need to work hand in hand to inform the process of the other.

Definitions used in the standard

6.1. Verification refers to the static process of checking documents and files, and comparing them to model parameters, model structure, or equipment settings.

6.2. Validation refers to the dynamic process of testing or monitoring the in-service equipment behavior, and then using the testing or monitoring results and comparing them to the model simulated response.

4. For Attachment 1, Row 2, "Initial verification for a newly commissioned Facility," ATC suggests that the GO transmit a verified model and accompanying information to the Transmission Planner within 180 calendar days instead of 365 calendar days after the commissioning date. Waiting a full year with a potentially inaccurate model before a plant gets updated through validation could prove to be too long and could result in significant delays.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	
Document Name	
Comment	

Comments: Proposed change to Facilities Section to more clearly align with the approved BES Definition (see below):

4.2. Facilities: For the purpose of this standard, the term “applicable units” shall mean any one of the following:

4.2.1 Individual generating resource **meeting the unit criteria set by** Inclusion I2 of the BES definition.

4.2.2 Generating plant/Facility **meeting the plant/Facility criteria set by** Inclusion I2 of the BES definition.

4.2.3 **Dispersed** power producing resources **that aggregate to a total capacity set by** Inclusion I4 of the BES definition.

4.2.4 Dynamic reactive resources **identified through meeting the criteria set by** Inclusion I5 of the BES definition with a gross nameplate rating greater than 20 MVAr, **or an aggregated site rating greater than 20 MVAr,** including, but not limited to:

4.2.4.1 Synchronous condenser; and

4.2.4.2 Flexible alternating current transmission system (FACTS) devices.

4.2.5 HVDC terminal equipment including:

4.2.5.1 Line commutated converter (LCC); and

4.2.5.2 Voltage source converter (VSC

Attachment 1 (Model Verification Periodicity) Comment

EEI suggests the following changes to Row 11, noting that OEMs are under no specific obligation to provide the models identified in MOD-026-2, unless such a requirement was written into the contract at the time the resource was purchased.

Verification Conditions:

Commissioning date of the Facility is before January 1, 2015;

OR

OEM is no longer in business; OR

OEM no longer supports model(s) for in-service equipment at

the Facility**; OR**

OEM is unwilling (or otherwise unable) to provide the supporting model (s) for in-service equipment at the Facility.

(Requirement R6 exemption

Throughout MOD-026-2 it uses the legacy title of Planning Authority. EEI suggests that the wherever this term is used, it be replaced with the preferred term “Planning Coordinator.

Section C “Compliance”

EEI asks the SDT to use the most up-to-date language in this section.

Section E “Associated Documents”

EEI asks the SDT to add the Implementation Plan and Technical Rationale to this section.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Proposed change to Facilities Section to more clearly align with the approved BES Definition (see below):

4.2. Facilities: For the purpose of this standard, the term “applicable units” shall mean any one of the following:

4.2.1 Individual generating resource **meeting the unit criteria set by identified through** Inclusion I2 of the BES definition.

4.2.2 Generating plant/Facility **meeting the plant/Facility criteria set by** Inclusion I2 of the BES definition.

4.2.3 **Dispersed** power producing resources **that aggregate to a total capacity set by** Inclusion I4 of the BES definition.

4.2.4 Dynamic reactive resources **meeting the criteria set by** Inclusion I5 of the BES definition with a gross nameplate rating greater than 20 MVA**r**, **or an aggregated site rating greater than 20 MVAr,** including, but not limited to:

4.2.4.1 Synchronous condenser; and

4.2.4.2 Flexible alternating current transmission system (FACTS) devices.

4.2.5 HVDC terminal equipment including:

4.2.5.1 Line commutated converter (LCC); and

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Attachment 1 (Model Verification Periodicity) Comment

EEI suggests the following changes to Row 11, noting that OEMs are under no specific obligation to provide the models identified in MOD-026-2, unless such a requirement was written into the contract at the time the resource was purchased.

Verification Conditions:

Commissioning date of the Facility is before January 1, 2015;

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OEM is no longer in business; OR

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(Requirement R6 exemption

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Section C "Compliance"

EEI asks the SDT to use the most up-to-date language in this section.

Section E "Associated Documents"

EEI asks the SDT to add the Implementation Plan and Technical Rationale to this section.

Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Derek Brown, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster

Answer	
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) to question #9.

Likes 0	

Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy supports EEI's comment.	
Likes 0	
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
See comments from Glen Farmer at Avista.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
Nothing in addtion to the proposed change from PA to PC in Q2 and the potential clarifying language identified in the response to Q3 and Q4.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

AEP appreciates the efforts of the Standards Drafting Team. While we disagree with some aspects of what was proposed in the most recent draft, AEP supports the SDT's overall goals and objectives.

AEP believes that in addition to HVDC, FACTS, and Synchronous Condensers, the following facilities would also be brought into scope in the proposed standard, and requests that clarity be added to the technical justification and mapping document to affirm these additional inclusions.

* Individual generating units 20-100 MVA with POI 100 kV and greater in Eastern Interconnection.

* Aggregate generating units 75-100 MVA with POI 100 kV and greater in Eastern Interconnection.

* Individual generating units 20-50 MVA with POI 100 kV and greater in ERCOT.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE has the following additional comments regarding clarification:

Facilities Section

In the facilities section, this standard says that it applies to resources/facilities that meet the BES Inclusions, but it does not mention the BES Exclusions. BES resources/facilities are determined by applying the Inclusions and then applying the Exclusions (for example, Exclusion E2). By only referring to the Inclusions in the facilities section, this standard could apply to some non-BES resources/facilities. Is this the intent of the SDT?

Also, is it the intent of the SDT that the HVDC terminal equipment should be BES? If so, a reference to the BES definition is needed for 4.2.5

Finally, Blackstart units are included as a separate category in the Inclusions of the BES definition. Texas RE recommends including Blackstart units in this standard applicability since the goal is to ensure accurate models for engineers to adequately study system conditions.

Texas RE recommends the following revisions to address the concerns regarding the Facilities section:

4.2.1 Individual generating resource identified through *Inclusion I2 the application* of the BES definition.
4.2.2 Generating plant/Facility identified through *Inclusion I2 the application* of the BES definition.
4.2.3 Generating plant/Facility of dispersed power producing resources identified through *Inclusion I2 the application* of the BES definition.

4.2.4 Dynamic reactive resources identified through *Inclusion I2 the application* of the BES definition with a gross nameplate rating greater than 20 MVA including, but not limited to:
4.2.4.1 Synchronous condenser; and
4.2.4.2 Flexible alternating current transmission system (FACTS) devices.
4.2.5 HVDC terminal equipment *identified through the application of the BES definition* including:

4.2.5.1 Line commutated converter (LCC); and
4.2.5.2 Voltage source converter (VSC).

4.2.6 Blackstart resource identified through the application of the BES definition.

Evidence Retention Section

Texas RE recommends the retention before 10 years in order for the entity to demonstrate compliance for the verified tests.

Attachment 1

As a general matter, Texas RE recommends including the attachment information in the requirement language to minimize the dependency on extraneous information. That said, Texas RE seeks clarification regarding the language on the following rows in Attachment 1:

Row 1 - Texas RE recommends clarifying the phrase “implementation period”. For MOD-026-1 there was a phased-in implementation for the fleet. Is the SDT indicating that a fleet percentage should still be considered from MOD-026-1 Implementation Plan (and therefore 100% be met by July 1, 2024- 10 years after the July 1, 2014 effective date of MOD-026-1)? Please see Texas RE’s comment on #8.

Row 2 - Texas RE recommends using the term registration date as there is no consistent and clear definition of commissioning date.

Row 4 – Texas RE recommends repeating or referring to the measure for Requirements R3 or R5 to explain how compliance should be met.

Rows 5 and 6 refer to Requirements R7, R8, and R9. None of these requirements reference Attachment 1 and they each have periodicities in the requirements. Should the requirement language reference attachment 1?

Row 5 - It appears that this should reference R7, rather than R8 since R7 discusses the change of in-service equipment and the obligations to supply information.

Row 7 – Texas RE recommends describing the phrase “same components and settings” in more detail as it is pretty broad. If one component or setting was different, demonstration of compliance becomes more challenging.

Row 8 - Texas RE recommends the information in rows 8 and 9 be included in the requirement language. It is somewhat buried in this attachment and would be easy to miss. Additionally, Texas RE requests justification for the exemption language. The response characteristics should be provided to the TP. Texas RE recommends referring to the measures in the requirements for which information should be provided to the TP.

Row 10 - Texas RE does not agree that current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31, of 5% or less should be a reason to be exempted from the periodicity in Requirements R2, R3, R4, R5, or R6. A low capacity factor means the unit does not run often, which implies that when it does run, it is needed. The TP should understand all scenarios.

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1

Answer	
Document Name	

Comment

· It is recommended the SDT consider using bullet points instead of long sentences. Using R5 as an example:

For…

- Inverter based resources (IBRs) identified in Section 4.2.3,
- LCC HVDC identified in Section 4.2.5.1, and
- VSC HVDC identified in Section 4.2.5.2,

Each Generator Owner or Transmission Owner shall provide…

- A verified positive sequence dynamic model(s),
- Associated parameters, and
- Accompanying information

…that represent the in-service equipment of the Facility to its Transmission Planner. This in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)shall include at a minimum the following:

The inclusion of the Planning Authority (Coordinator) should be reconsidered as it is not consistent with the existing MOD-026 & 072 standards that are being combined and, in the proposed standard, is redundant with MOD-032.

The VRFs for R2 – R6 match in the SDT proposed standard. The SDT should consider making the VRF for R7 consistent with the VRF for R2 – R6.

The SDT should consider whether the “Operations Planning” time horizon is appropriate for this standard. “Long-term Planning” appears to be the more appropriate choice for the entire standard.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3

Answer	
Document Name	

Comment

WEC Energy Group supports EEI and NAGF comments.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	
Document Name	

Comment

Black Hills Corporation supports EEI and NAGF comments.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	
Document Name	

Comment	
RE: Facilities: What was the rationale to propose augmenting the inclusion of dynamic reactive power resources, per I5, with a 20MVA threshold? This seems to not fully follow the statement in the Technical Rationale Document for Reliability Standard MOD-026-2, "[t]he proposed standard links applicability to the BES definition (as opposed to defined rating or other thresholds) to be sure that now and in the future, should the BES definition be modified, the standard is consistent with applicable BES facilities" In addition, National Grid supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Aric Root - CMS Energy - Consumers Energy Company - 4	
Answer	
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	

Document Name	
Comment	

The additional applicability of the standard to all BES generators and HVDC equipment will benefit reliability with the provision of verified models for additional equipment. Also, the provision of EMT models for inverter based resources is important to maintain reliability and preclude events such as the Odessa disturbance.

Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO

Answer	
Document Name	
Comment	

The MRO NSRF recommends the following:

• Removing the 90-day, 180-day, and 365-day arbitrary deadlines and replacing with the joint PC / TP model building process. Many PC and TP's build models approximately annually. Shorter deadlines measured in days aren't useful or efficient, rather they become administrative compliance burdens and should all be eliminated.

• The MRO NSRF suggests modifying requirements that entities provide models with "according to the PC / TP joint modeling process unless within 3 calendar months of the data submission deadline upon the models will be provided during the next cycle.

• The MRO NSRF suggests the drafting re-instate the 100 MVA thresholds originally justified as providing over 80% of the NERC Bulk Electric System units. The current technical rationale of "This avoids the need to modify the standard if definitive thresholds are specified and the BES definition is modified" isn't a sufficient justification to remove the original threshold.

• The MRO NSRF suggests replacing the use of the "365 calendar days" terminology with 12 calendar months. This greatly simplifies the scheduling and aligns with MOD-025.

• The MRO NSRF suggests the SDT add specific language for any existing unit newly brought into the scope of this standard. New units or plants need the same "10 year implementation plan" similar to version 1 of MOD-026 and -027.   It must be realized that the original 10 year modeling effort will repeat, and the entities charged with this work again need to be permitted to control the schedule so that it can be levelized over time and not overloaded in one small section of the 10 year cycle.

Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	

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

Answer	

Document Name	
Comment	

To better align with the Standards Alignment with Registration NERC project (2017-07), Planning Authority should be replaced with the Planning Coordinator in all documents related to this project (MOD-026-2, Implementation Plan, Mapping Document, VRF/VSL Justifications, and Technical Rationale).

The Transmission Owner should not be responsible for gathering modeling data for equipment we do not own. MOD-026-2 Verification of Dynamic Models and Data for BES Connected Facilities applies to GO, TP, PA, and **TO**. The way certain requirements are written (the drafting team may have had good intentions) gathering of data is not only the responsibility of the GO (as it should) but it has a statement "or Transmission Owner".

Examples:

R2: **For synchronous generation identified in Section 4.2.1 or 4.2.2** or a synchronous condenser identified in Section 4.2.4.1, each Generator Owner or **Transmission Owner shall provide a verified positive sequence dynamic model(s), associated parameters, and accompanying information that represents the in-service equipment of the Facility to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1.**

I am guessing TO would be responsible for the "synchronous condenser"? This should be written to tie it to the owner.

R4: **For inverter-based resources (IBRs) identified in Section 4.2.3**, FACTS devices identified in Section 4.2.4.2, and VSC HVDC identified in section 4.2.5.2, each Generator Owner or **Transmission Owner shall provide a verified positive sequence dynamic model(s), associated parameters, and accompanying information that represents the in-service equipment of the Facility to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1.**

NPCC RSC does not agree with the ten-year period described in Attachment 1, Rows 3 & 7 due to the potential for frequent changes to the maturing technology of utility-scale inverters. Inverter manufacturers will undoubtedly issue numerous upgrades and security fixes to the inverter firmware over a 10-year period. The GO or TO will install many of these firmware upgrades and likely all of the security-related ones so as to not be hacked because of known insecure firmware. Since firmware changes can notably impact the operation of the inverter, Eversource suggests changing the 10-year period to a 5-year period in order to balance the need for accurate models with the burden of verifying what the models should be.

Likes 0	
Dislikes 0	
Response	

George Brown - Acciona Energy North America - 5

Answer	
Document Name	
Comment	

Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
-Exelon concurs with the comments submitted by the EEI for Question #9. Submitted on behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	
MidAmerican supports MRO NSRF and EEI comments.	
Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
1. Verified model versus Validated model At many locations in MOD-026-02 (ex: R7, R9, Attachment 1, etc.), the “verified model(s)” terminology is used. According to section 6 “Standard-Only Definitions”, this excludes comparing testing or monitoring results with model simulated response. Can you confirm that this involves only “checking documents and files, and comparing them to model parameters, model structure, or equipment settings”, as defined at section 6.1? If the answer is negative, please clarify text.	

2. Enlarged scope for MOD-026

MOD-026-02 covers multiple set of equipment, in opposition to MOD-026-01 and MOD-027-01 where each covers only one set of equipment. MOD-026-02 must clearly state that each requirement (R1 to R9) can be met individually, including dates, periodicity, content, transmittal of information, etc.

3. Definition of "Newly Commissioned Facility"

What is the definition for the "newly commissioned facility" term used at rows 2 and 11 of attachment 1 of MOD-026-02? Our understanding is that it means a new commissioned power station. This would exclude any turbine-generating unit overhaul from complying to requirements R2 to R6. Please define term "Newly Commissioned Facility".

4. Change to in-service equipment

Row 5 of Attachment 1 of MOD-026-02 should refer to R7, not R8, in the "Verification Condition" column.

5. Equivalent Unit Verification Condition

At row 7 of attachment 1 of MOD-026-02, it is mentioned that this row applies when "calculating generation fleet compliance during the implementation period". This is in line with row 1. However, the following sentence from the "Required Action" column of row 7 brings confusion: "Verify the model(s) of a different equivalent unit during each 10-year verification period." If the equivalent unit verification condition applies only during the implementation period, it does not make sense to mention any periodicity. Please clarify text. Original MOD-026-01 and MOD-027-01 have the same issue.

Likes 0	
Dislikes 0	

Response

Durga Gautam - GE - GE Wind - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

Attachment 1, Row 9: Most IBR units in service today are not required to leave the 'headroom' in active power that would be required to have a response to under-frequency, per the FERC 842 ruling. A statement should be added to clarify this.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	

1. The Technical Rationale page 2, paragraph 3 is functionally incorrect. This language perpetuates the poorly used term "database" from MOD-026-1 and MOD-027-1 Requirement R1 (bullet 3) which is problematic if interpreted that Transmission Planners are obligated to maintain a database of Generator Owner or Transmission Owner models. This is inconsistent with MOD-032-1 for jointly developed modeling data requirements and reporting procedures of the Transmission Planner and Planning Coordinator, as well as the requirement for Generator Owner or Transmission Owner to submit modeling data to its Transmission Planner and Planning Coordinator. Transmission Planners are not required to maintain a database of models from which Generator Owners and Transmission Owners obtain. On the contrary, the closest requirement to one that requires models to be made available is given in MOD-032-1 Requirement R4 which obligates each Planning Coordinator to make models available to the ERO or designee.

2. The Technical Rationale page 4, paragraph 3 ("Part 1.4") is incorrect. It should be revised to state:

Part 1.4 was not directly included in MOD-026-1 or MOD-027-1. Part 1.4 requires that a process for submitting models to by the GO and TP TO is developed jointly by the its Transmission Planner and Planning Authority and is made available to submittal parties. This part is an addition to the previous MOD-026-1 standard and is intended to aid in model submittal efficiency by providing clear submittal processes to by the GO and TO.

3. The MOD-026-2 Attachment 1 uses inconsistent possessive form of Transmission Planner and the representative pronoun.

Row 1 "Required Action" should be revised to:

Transmit the verified model and accompanying information to the its Transmission Planner in accordance with the Implementation Plan.

Row 2 "Required Action" should be revised to:

Transmit the verified model and accompanying information to the its Transmission Planner within 365 calendar days after the commissioning date.

Row 3 “Required Action” should be revised to:

Transmit the verified model and accompanying information to the its Transmission Planner on or before the 10-year anniversary of the most recent transmittal date.

Row 4 “Required Action” should be revised to:

Requirement R3 or R5 is met with a written statement transmitted to the its Transmission Planner. Transmit the verified model and accompanying information to the its Transmission Planner on or before 365 calendar days after a frequency excursion per Note 1 occurs and the recording equipment captures the applicable unit’s real power response as expected.

Row 5 “Required Action” should be revised to:

Transmit the verified model and accompanying information or a mutually-agreed upon plan to the its Transmission Planner within 180 calendar days after making the change to in-service equipment. If mutually-agreed upon plan is provided to the its Transmission Planner, then Row 6 applies.

Row 6 “Required Action” should be revised to:

Transmit the verified model and accompanying information to the its Transmission Planner within 180 days after the verification date specified in the mutually agreed upon plan.

Row 7 “Required Action” should be revised to:

Document circumstance with a written statement and include with the verified model, documentation and data provided to the its Transmission Planner for the verified equivalent unit.

Row 8 “Required Action” should be revised to:

Requirement R2 or R4 is met with a written statement to that effect transmitted to the its Transmission Planner.

Row 9 “Required Action” should be revised to:

Requirement R3 or R5 is met with a written statement to that effect transmitted to the its Transmission Planner.

Row 10 “Required Action” should be revised to:

Requirement R2, R3, R4, R5, or R6 are met with a written statement to that effect transmitted to the its Transmission Planner annually.

Row 11 “Required Action” should be revised to:

Requirement R6 is met with a written statement to that effect transmitted to the its Transmission Planner.

Likes 0	
Dislikes 0	

Response

Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1

Answer	
Document Name	

Comment

4.2.4 states, “…including, but not limited to:” but there is no mention of 4.2.4 facilities outside of the specific facilities defined in 4.2.4.1 and 4.2.4.2. Are SVCs applicable under the standard? Should “but not limited to:” be removed from 4.2.4?

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5

Answer	
Document Name	

Comment	
City of Austin dba Austin Energy supports LPPC's comment as follows: • Currently, WECC has an EMT Task Force in place to provide guidance to WECC members on EMT models and discuss varios software options. Registered Entities will need all Regional Entities to provide some similar support by creating EMT Task Forces. This collaboration allows entities to learn from the expertise of others and helps ensure that data from the models can be shared.	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF agrees with EEI's comments and recommended changes. The NAGF requests that the SDT evaluate and clarify the language under draft MOD-026-2 Attachment 1 "Model Verification Periodicity" specifically Row 9 that gives an exemption to R3 or R5 requirement to provide a validated model (and therefore any associated testing or analysis) for any unit that meets the conditions of the Row (i.e., a written statement to the TP stating the unit meets the condition is sufficient to meet the R3 or R5 requirements). The Verification Condition stated in Row 9 has historically been interpreted by GOs in two different ways: 1. The row applies if the unit does not respond in either direction: a. Unit does not respond to over frequency events, and b. Unit does not respond to under frequency events. 2. The row applies if the unit responds in just one direction: a. Unit does not respond to an over frequency event but does respond to an under frequency event, or b. Unit does not respond to an under frequency event but does respond to an over frequency event. [Reference draft NERC Compliance Guidance submitted by the NAGF on 8/30/17 and RFI on MOD-027-1 submitted by the NAGF dated 12/11/17]. "Applicable unit is not responsive to both over- and underfrequency excursion events during normal operation," in Att. 1 row 9 would be clearer as, "Applicable unit is not responsive to frequency excursion events or can respond in only one direction." This exemption is often taken for the sliding pressure operation of combined cycle STGs (in MOD-027-1 row 7), but while a wide-open valve cannot admit more steam it can always close for over-frequency. It was agreed in a recent discussion with the 2020-06 SDT that the proposed rewording is what was intended when MOD-027-1 was introduced, and although the NAGF previously communicated this concern to NERC the present text is still open to multiple interpretations.	
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

PG&E currently has approved MOD-027-1 exemptions for Requirement R2 that were allowed under MOD-027-1 Attachment 1, Row 7. The R2 exemption was carried forward in MOD-026-2 Attachment 1, Row 8, which PG&E appreciates. PG&E respectfully requests that the project team add additional language to Attachment 1 that allows for grandfathering of existing exemptions similarly to MOD-27-1. This will allow entities to not have to re-apply under MOD-026-2, which allows for administrative and operational efficiencies.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis

Answer	
Document Name	

Comment

The SRC is requesting the BES definition should be modified to capture wholesale generators (e.g. 50 MW generator on 69 kV). This change supports correcting unit models for larger generators that are connected to <100kV as the units would now be applicable to the Standard. At a minimum, the SRC requests existing MOD-026-1 section 4.2.4 language be retained in MOD-026-2 to support generator models of generators connected to <100kV.

The SRC also recommends "Planning Authority" be revised to "Planning Coordinator" in Applicability section 4.1.3 and similar throughout MOD-026-2 wherever Planning Authority is used.

The SRC wants to take this opportunity to thank the Standard Drafting Team for all their work and commitment to this Project. This is sincerely appreciated.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer	
Document Name	

Comment

Eversource does not agree with the the ten year period described in Attachment 1, Rows 3 & 7 due to the potential for frequent changes to the maturing technology of utility-scale inverters. Inverter manufacturers will undoubtedly issue numerous upgrades and security fixes to the inverter firmware over a 10-year period. The GO or TO will install many of these firmware upgrades and likely all of the security-related ones so as to not be hacked because of known insecure firmware. Since firmware changes can notably impact the operation of the inverter, Eversource suggests changing the 10-year period to a 5-year period in order to balance the need for accurate models with the burden of verifying what the models should be.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Currently, WECC has an EMT Task Force in place to provide guidance to WECC members on EMT models and discuss various software options. Registered entities will need all Regional Entities to provide some similar support by creating EMT Task Forces. This collaboration allows entities to learn from the expertise of others and helps ensure that data from the models can be shared.

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

The ITC Standards Under Development Team has received no response to submit from the Standard Owners

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	
Document Name	
Comment	

Southern Company suggests removing the 90-day, 180-day, and 365-day arbitrary deadlines and replacing with the joint PA / TP model building process. Many PA and TP's build models approximately annually. Shorter deadlines measured in days are not useful or efficient, rather they become administrative compliance burdens and should all be eliminated.

We suggest modifying the requirements so that entities provide models "according to the PA / TP joint modeling process.

We believe that the verification / validation definitions are inadequate. A simulation comparison to staged test results is the best way to prove a model. Use of verification as defined in applicability section 6.1 leaves open the high probability of a never-ending open loop activity of model production for IBR sites that do not react identically to varying disturbance signals. Each system disturbance is likely to "look" different to the IBR equipment. Requiring a model that is 100% accurate for all types of system disturbances is not equitable to the stakeholders taxed with the obligation to do so. The equipment owner will never finish developing a model that is guaranteed to predict IBR controls with 100% certainty. A continual remodeling effort will never end – each time a system disturbance with a new characteristic results is a different facility reaction compared to an existing model, a revised model will be requested.

We suggest the drafting retain the 100 MVA thresholds originally justified (EI) as providing over 80% of the NERC Bulk Electric System units. The current technical rationale of "This avoids the need to modify the standard if definitive thresholds are specified and the BES definition is modified" isn't a sufficient justification to remove the original threshold. We are concerned with the expanded scope of units included in the modeling scope. The Initial scope was not down to individual units > 20 MVA. It was believed by the original MOD-026 & -027 standard drafting team members that the % of units included in the MVA threshold chosen would adequately provide information to predict the system response using simulation. All units above 20MVA now in scope. No justified basis for this increased scope has been provided. We believe that the additional amount of work and cost to the few additional % of MVA coverage is not justified. It should be clarified that the 20MVA threshold applies to single generating units and not the plant size - as many solar and wind facilities are over 20MVA but under the 75MVA aggregate threshold requiring NERC registration

We suggest replacing the use of the "365 calendar days" terminology with 12 calendar months. This greatly simplifies the scheduling and aligns with MOD-025.

We recommend the replacement of "Transmission Planner" with "Transmission Planner and/or Planning Authority" in Requirements R1.3., R1.4, R1.5, R4, R5, R6, R7, R8, and R9

Likes 0	
Dislikes 0	

Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	
Document Name	
Comment	
It will generally be confusing and illogical for some requirements of the PC/TP for models/modeling data to be in MOD-032 and some in MOD-026. The “seems” between these standards need some work. We know this is not an easy path, but we feel it is most logical/clean path and will greatly improve the ability to comply. Also please keep in mind the limitations of technical staff that some GOs face when it comes to transmission system stability and EMT modeling.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
• Although it appears NERC uses “Planning Authority” and “Planning Coordinator” interchangeably, ERCOT recommends using Planning Coordinator (rather than Planning Authority) consistent with the functional model and direction provided to other standard development projects. ERCOT suggests the SDT take an approach similar to the current MOD-032-1 applicability. Proposed language (which would need associated change from PA to PC within entire standard):	

Applicability *4.1.3 Planning Authority and Planning Coordinator (hereinafter collectively referred to as “Planning Coordinator”)* *This standard combines “Planning Authority” with “Planning Coordinator” in the list of applicable functional entities. The NERC Functional Model lists “Planning Coordinator” while the registration criteria list “Planning Authority/Planning Coordinator.” Until these are synchronized, this standard applies to both Planning Authority and Planning Coordinator.* • The standard-only definition for “verification” is problematic because “verification,” as used within the standard, implies a broad definition that encompasses “validation” rather than being the separate, distinct terms provided in the definition section of the standard. • The table in Attachment 1 (Model Verification Periodicity) uses the words ‘unit’ and ‘Facility.’ Because this standard applies to transmission and generation facilities, ERCOT recommends using consistent and appropriate terms.	
Likes 0	
Dislikes 0	
Response	
James Howell - Southern Company - Southern Company Generation - 5	
Answer	
Document Name	
Comment	
See Southern Company Comments	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
What is the basis for changing from the current MOD-026-1/MOD-027-1 applicability of individual units greater than 100 MVA (Eastern Interconnection) to individual units greater than 20 MVA (i.e. changing to the BES Definition I2 inclusion)? This will significantly increase the number of units that fall under the standard’s requirements. If the Drafting Team proceeds with a single standard, we recommend the requirements be segmented with headers (reference TPL-007-4) that help clarify the types of resources/devices to which they apply (E.g., Synchronous Generation, Synchronous Condensers, Inverter Based Resources, etc.) and/or the applicable entity actions (Dynamic Modeling Data Specification, Dynamic Modeling Data Verification, Exchange of Dynamic Modeling Data, etc.).	

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	
Document Name	

Comment

SPP suggests the drafting team consider changing the applicable entity of the Planning Authority to the Planning Coordinator. This supportive change was made in Version 3 of the NERC Functional Model which was approved February 13, 2007.

Furthermore, a significant increase in scope applicable to PA/PC and uncertainty around interactions with the future MOD-032 SAR create concerns for the 12 months after the NERC Board of Trustee adoption date along with the 24 months after the effective date.

In most situations, RTOs and PCs will have to seek approval of incremental headcounts which can be a 12-month process for full approval. After approval, it could take an additional 6 months to hire and train staff to appropriately perform the complex and specific work required under this standard. Additionally, coordination in the development of a process could take an additional 12 months.

Additionally, we suggest that the effective date be 24 months after the NERC board adoption to better coordinate considerations from the future MOD-032 SAR, and allow adequate staffing preparation.

Likes 0	
Dislikes 0	

Response

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County

Answer	
Document Name	Question 9 - Reference 3 and 7.PNG

Comment

1. “Change” is not in the Glossary of terms as it applies to R7 (Attachment 1, Row 6). What qualifies as a change to in-service equipment per R7. When a large synchronous generator (such as a hydro generator) is completely rehabbed, it technically is a change to an existing generator at the plant. It is also considered a new generator as it has a new rotor, stator, turbine, etc. Attachment 1, Row 2 defines the deadline requirements for “Initial verification for a newly commissioned Facility” for R2 and R3. In the example stated above, would a rehabbed generator be a “change” to an existing facility or a “new” facility?

2. As mentioned previously, the Planning Coordinator is brought into the standard unnecessarily, and it would appear beyond the scope of the SARs. Also, NERC currently uses Planning Coordinator, not Planning Authority as is currently drafted in this proposed revision.

3. The standard requirements are filled with many references to the Applicability portion of the standard. However, this is not clear from the requirement text; it is recommended that a clarifying ‘Applicability’ prefix be added to such references in the proposed R2, R3, R4, R5, R6, and as

shown in the example attached for R2.

4. Many of the more prescriptive modeling requirements (such as relay models and relay types) appear to be in duplication of allowances provided to the Transmission Planner and Planning Coordinator under MOD-032. This should be avoided.

5. As mentioned previously, the addition of protection system requirements found in R2, R3, R4, and R5 is concerning as these did not appear in any of the SARs.

6. Similarly, the addition of EMT model requirements are also not found in the SARs (R1, R6 of the proposed MOD-026-2)

7. For the new proposed R3.2., the new language has removed some of the examples that were helpful under MOD-027 R2.1.5. These examples should be restored if possible. Without these, the new R3.2. language is very vague as to what functions are intended by its description, please see attached reference.

8. It is somewhat confusing that the Transmission Planner is required to develop an acceptance process and criteria under R1, but under R8 they are not directly required to utilize the R1 criteria. This could be strengthened in R8's language if R1 is maintained. However, but the Transmission Planner language found in the current MOD-026 R6 and MOD-027 R5 describing the Transmission Planner review process is preferred to the new proposed MOD-026-2 R1 and R8 language re-defining this process. Again, the SARs don't seem to identify a need to revise these requirements so this change would appear out of scope.

9. The new MOD-026-2 draft appears to remove the provisions in the current MOD-026 R3 and MOD-027 R3 where the Transmission Planner could, apart from the normal testing schedule, notify the Generator Owner of issues regarding the generator excitation or governor model and request a resolution. This takes away an important tool from the Transmission Planner in maintaining usable models. It is recommended those MOD-026 R3 and MOD-027 R3 provisions be maintained to carry forward this function in the new proposed MOD-026-2.

Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	

Agree with comments by PUD No. 1 of Chelan County, WA

Please remove "plant" from subsection 4.2.3 to avoid any confusion on how this should be interpreted. The BES definition does not use this term anywhere in Inclusion I4. Further, note that Inclusion I4 encompasses the *system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.* The applicability section should take care not to include Facilities having no bearing on the Standard.

Finally, do not agree with use of "Planning Authority." Please use "Planning Coordinator."

Likes 0	
Dislikes 0	
Response	

Glenn Pressler - CPS Energy - 3	
Answer	
Document Name	
Comment	
No comment; however, believe much more industry expertise in modeling and studying capabilities are needed before Requirements such as these can be implemented and enforced.	
Likes 0	
Dislikes 0	
Response	