NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2020-06 Verifications of Models and Data for Generators | Draft 2
Comment Period Start Date:	11/21/2022
Comment Period End Date:	1/18/2023
Associated Ballot(s):	2020-06 Verifications of Models and Data for Generators Implementation Plan AB 2 OT 2020-06 Verifications of Models and Data for Generators MOD-026-2 AB 2 ST

There were 77 sets of responses, including comments from approximately 200 different people from approximately 130 companies representing 10 of the Industry Segments as shown in the table the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Director, Standards Development Latrice Harkness (via email) or at (404) 858-8088.

Questions

1. Do you agree as a whole that Draft 2 of MOD-026-2 is an improvement to Draft 1? If you do not agree, please provide an explanation.

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 2 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 3 years for compliance with Requirements R2-R6 for newly applicable Facilities. For existing Facilities, the Implementation Plan proposes the 10-year reoccurring periodicity is maintained from the date of previous model verification. Do you agree with the proposed implementation plan timeframes? If you think an alternate timeframe is needed, please propose an alternate implementation plan with detailed explanation.

9. Provide any additional comments on the standard and technical rationale for the SDT to consider, if desired.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

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
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Daniel Mason	Portland General Electric Co	6	WECC
Public Utility District No. 1 of Chelan County	Diane E Landry	1		CHPD	Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
Elizabeth Davis	Elizabeth Davis		RF,SERC	ISO/RTO Standards Review Committee	Mike Del Viscio	PJM	2	RF
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Helen Lainis	IESO	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Nathan Bigbee	ERCOT	2	Texas RE
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
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Ryan Strom	Buckeye Power, Inc.	5	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Dave Hartman	Arizona Electric Power Cooperative	1	WECC
					Scott Brame	NC Electric Membership Corporation	3,4,5	SERC
JEA	Joseph McClung	1	FRCC	LPPC	Joe McClung	JEA	1,3,5	SERC
					Tim Kelley	SMUD	1,3,4,5	WECC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Michael Ayotte	ITC Holdings	1	MRO
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Santee Cooper	Marty Watson	5		Santee Cooper	Paul Camilletti	Santee Cooper	1,3,5,6	SERC
					Lachelle Brooks	Santee Cooper	1,3,5,6	SERC
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
					Frank Lee	Pacific Gas and Electric Company	5	WECC
Southern Company -	Pamela Frazier	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company -	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Southern Company Services, Inc.						Southern Company Services, Inc.		
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Sheraz Majid	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					John Hastings	National Grid	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Dan Kopin	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Randy MacDonald	New Brunswick Power Corporation	2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Matt Harward	Southwest Power Pool Inc	2	MRO
					Sunny Raheem	Southwest Power Pool Inc	2	MRO
					Lottie Jones	Southwest Power Pool Inc.	2	MRO
					Rebecca McCann	Southwest Power Pool Inc.	2	MRO
		10		WECC	Steve Rueckert	WECC	10	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Western Electricity Coordinating Council	Steven Rueckert				Phil O'Donnell	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD / BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power	3	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Cooperative (Missouri)		
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Do you agree as a whole that Draft 2 of MOD-026-2 is an improvement to Draft 1? If you do not agree, please provide an explanation.	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
The majority of the recommendations and concerns Oncor submitted in the last ballot period were not addressed in this revision.	
Likes 0	
Dislikes 0	
Response	
The SDT attempted to respond to all comments received from this posting.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Manitoba Hydro appreciate the changes that the SDT made to the Draft-1. However, we still believe the revised draft standard need more clarifications as outlined below. 1) The way it is written, R1.2 always requires TP/PC to develop EMT model requirements irrespective of whether they need such models or not. We believe TP/PC should have the flexibility to determine the level of detail of EMT models and when it is required. This is the language that we can see in Part 1.2 of the Technical Rationale document. Such an important requirement should be clearly specified within the standard rather than referring to supplementary technical documents.	

2) Draft 2 does not address 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. It is more difficult to share user's defined models with other PCs and more difficult to maintain and validate the user's defined models).

3) Draft 2 does not encourage dialogue between entities to ensure a cost-effective manner to meet the TP/PC required modeling details. Adding more details such as more protection elements to the minimum modeling requirements without considering the actual TP/PC modeling details requirements, type of studies and studies issues is not the right way to go. It should be left up to the TP/PC to communicate to the generator and transmission owners the minimum modeling requirements to address their concerns and needs.

Likes 0	
Dislikes 0	

Response

R1 does give the TP authority to decide the level of detail of the EMT models. Additional intention and justification of Requirement R1.2 is provided in the Technical Rationale. The SDT wanted to keep the requirement language simple.

"Where determined" leaves the decision up to the TP and adds ambiguity for which projects would need to submit verified EMT models, and which would not. This would put burden on the GOs in that they would not be able to adequately plan for the increased costs of EMT models. Also NERC has in multiple documents discerned that it is important to collect EMT models before they are required for any individual project or study.

Standardized EMT models are not sufficient for inverter based resource studies. Standard models are readily available for passive elements, but for inverter/converter control technologies, manufacturer written models are necessary.

If this is in reference to EMT models then this is moot. EMT models must be user written, otherwise they are not useful.

NERC Disturbance reports have shown that this methodology does not always work. The standard seeks to set a minimum requirement.

Brian Lindsey - Entergy - 1

Answer	No
Document Name	

Comment

Changes to R7 make it less clear on the scope of changes that requires a new model. However, the changes to R8 are welcomed improvements.

Likes 0	
Dislikes 0	

Response

Footnote of changes in scope for R7 was added back into the standard.

Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD

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

Requirements R2/R3 and R4/R5 do not need to be completed at the same time. Though from an efficiency standpoint, it would make sense to do so.

This can still be achieved by completing the requirements at different times. There is an efficiency gain since 4-5 requirements could be retired for the process related items of reviewing and responding to questions.

This is a fair point. The SDT acknowledges that there will be change associated with this version of MOD-026-2. The SDT also felt that the addition of Requirement R6 was best to be part of MOD-026 rather than a separate standard, since there are similar activities and processes for positive sequence and EMT models.

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

The MRO NSRF appreciates the SDT's goal of moving industry forward in a new and technical area.

· However, the MRO NSRF must pragmatically break the goal of developing EMT models down into manageable steps to be fully compliant.

· The SDT revision to 36 months is not sufficient.

· Fundamentally, industry is resource limited as there aren't a sufficient number of EMT experts.

· Industry must have at least 60 months to purchase software, train personnel and verify models. This is still an aggressive goal at 60 months.

The MRO NSRF appreciate the changes the SDT made. However, important structural changes suggested by the MRO NSRF in draft 1 were not adopted.

Key structural concerns included:

· R1 still requires EMT models at all times without deferring to when the TP or PC requests them. While footnote 2 discusses the level of detail, it doesn't provide the TP with the flexibility to determine when EMT models are required.

· 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 "where determined and in accordance with the PC and TP joint model process in the requirements".

· 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.

· Clarifying “Facility”. The MRO NSRF suggests the following changes to clarify:

4.2.1 For the purpose of this standard, the term “applicable Facility or Facility” subject to these requirements means:

4.2.1.1 A BES generator with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater; or

4.2.1.2: BES generating “plant” at the common Point of Interconnection meaning the transmission (high voltage) side of the main generator step-up transformer where more than 75 MVA of aggregate generation has been collected connected at 100 kV and greater. Individual generating resources below the common point of interconnection are excluded.

Likes 0	
Dislikes 0	

Response

Change made for Implementation Plan, increased to 5 years total for Compliance Date of R2-R6, and R7. Additionally, see Implementation Plan section *Initial Performance of Periodic Requirements, “*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). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.”

Regarding TP specified EMT requirement: Having an on-demand requirement for verified EMT models could be problematic. By having the TP define a need at any given time in the future, would create an emergent requirement for the GO to obtain an EMT model for an operational plant. For example, if a TP would require a verified EMT model in 2025, for a Facility commissioned in 2020, then the GO/TO would be considered a newly applicable Facility and have approximately one year to provide a verified EMT model to its TP. Whereas, with this approach all verified EMT models will need to be provided, if the Facility is commissioned after a specified date, which is a more straight forward approach. Obtaining verified EMT models is easier to achieve around the time of initial commissioning. Contracts that are in place with the equipment manufacturer allow for the delivery of a verified EMT model. Once the OEM is no longer under contract and more time passes, it becomes more difficult to obtain the required information. As more time passes from commissioning date, the risk increases that an OEM may no longer support the existing equipment, OEM personnel familiar with the technology or installation may have left the company, or the OEM may no longer be in business.

"Where determined" leaves the decision up to the TP and adds ambiguity for which projects would need to submit verified EMT models, and which would not. This would put burden on the GOs in that they would not be able to adequately plan for the increased costs of EMT models. Also NERC has in multiple documents discerned that it is important to collect EMT models before they are required for any individual project or study Standardized EMT models are not sufficient for inverter based resource studies. Standard models are readily available for passive elements, but for inverter/converter control technologies, manufacturer written models are necessary.

No change. The SDT feels the applicability language is clear.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
See MRO NSRF response.	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	

{C}· The MRO NSRF appreciates the SDT's goal of moving industry forward in a new and technical area.

{C}· However, the MRO NSRF must pragmatically break the goal of developing EMT models down into manageable steps to be fully compliant.

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{C}§ {C}4.2.1.1 A BES generator with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater; or

{C}§ 4.2.1.2: BES generating "plant" at the common Point of Interconnection meaning the transmission (high voltage) side of the main generator step-up transformer where more than 75 MVA of aggregate generation has been collected connected at 100 kV and greater. Individual generating resources below the common point of interconnection are excluded.

Likes 0	
Dislikes 0	

Response

See MRO NSRF response.

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
In order to ensure consistent EMT models are developed and implemented and that adequate EMT simulation tools are used IID planners will require time to be trained on EMT models, simulations and their corresponding tools and software. IID Transmission Planners are following regional group efforts that may standardize things such as model formats and acceptable software	
Likes 0	
Dislikes 0	
Response	
No change. R1 gives authority to the TP and PC to develop their own standards, which could mean that they follow the mentioned “regional group efforts”	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI's Comments which state: While the changes made to MOD-026-2 are an improvement, we still do not support Draft 2 because of the concerns described in our responses to Questions 2, 5, 6 & 9 .	
Likes 0	
Dislikes 0	
Response	
See EEI response.	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
See MRO NSRF response.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
While AEP appreciates the efforts of the Standards Drafting Team, it does not appear that most of the recent edits are substantive. So, while certainly not objectionable, we do not view the latest draft as a step forward or improvement of its predecessor.	
Likes 0	
Dislikes 0	
Response	
The SDT attempted to respond to all comments received from this posting. The goal was to make improvements from the previous draft of the standard, while explaining why some changes were not made.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment	
While BPA agrees that the NERC MOD-026 and MOD-027 standards need revising, BPA believes the SDT has overstepped the scope of the SAR by adding EMT models to the Verification of Models and Data for Generators in this draft.	
Likes 0	
Dislikes 0	
Response	
No change. See Technical Rationale for addition of EMT models in Requirement R6. The SAR specifically states that the purpose of the project is to add IBRs to the verification. There is no way to adequately verify and validate an IBRs response to events using traditional positive sequence RMS type simulations. EMT modeling is the only readily available way to do so.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Minor editorial comments incorporated in Draft 2 do not address overall Duke Energy and industry comments or concerns.	
Likes 0	
Dislikes 0	
Response	
The SDT attempted to respond to all comments received from this posting.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	

Per the BES definition of Inclusion I5, the rating is 100 kV and additionally, other inclusion references rating “aggregate of 75 MVA or greater”. See additional comments from the NAGF for question 6 & 8.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Per the BES definition of Inclusion I5, the rating is 100 kV and additionally, other inclusion references rating “aggregate of 75 MVA or greater”. See additional comments from the NAGF for question 6 & 8.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Per the BES definition of Inclusion I5, the rating is 100 kV and additionally, other inclusion references rating “aggregate of 75 MVA or greater”. See additional comments from the NAGF for question 6 & 8.	

Likes 0	
Dislikes 0	

Response

See NAGF response.

Josh Combs - Black Hills Corporation - 3

Answer	No
Document Name	

Comment

Per the BES definition of Inclusion I5, the rating is 100 kV and additionally, other inclusion references rating "aggregate of 75 MVA or greater". See additional comments from the NAGF for question 6 & 8.

Likes 0	
Dislikes 0	

Response

See NAGF response.

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

Answer	No
Document Name	

Comment

The main concerns for SIGE surrounding EMT models were not addressed during this revision.

Likes 0	
Dislikes 0	

Response

The SDT attempted to respond to all comments received from this posting.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
While AZPS agrees that many changes were made between drafts 1 & 2, AZPS does not agree that changes were made to issues that AZPS finds most significant. AZPS has provided addition information in its responses to questions 2 through 9 below which describe these issues in detail.	
Likes 0	
Dislikes 0	
Response	
The SDT attempted to respond to all comments received from this posting.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
The challenge with this standard is that most of inverter based interconnected Generation does not have a Transmission Planner. As a result of their absence of skill set in this area, the models that we get are incompatible with our region models.	
Likes 0	
Dislikes 0	
Response	

All area GO/TOs under NERCs jurisdiction should have an associated TP. This comment may be referring to DERs, however inverters connecting to the transmission system must be held to a higher standard.

Kristine Howie - Kristine Howie Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
Answer	No
Document Name	
Comment	
Constellation agrees and appreciates the consideration on allowing excitation and governor modeling to be completed separately. However, Constellation has additional concerns with the additional requirements around protection system components and potential additional costs remain. Kristine Howie behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Requirement R2 and R3 can be completed separately on different compliance timelines. Change made. List of Protection Systems in R2.3 was trimmed to a minimum. Protection Systems need only be modelled if they are installed and enables.	

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

Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation agrees and appreciates the consideration on allowing excitation and governor modeling to be completed separately. However, Constellation has additional concerns with the additional requirements around protection system components and potential additional costs remain. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Requirement R2 and R3 can be completed separately on different compliance timelines. Change made. List of Protection Systems in R2.3 was trimmed to a minimum. Protection Systems need only be modelled if they are installed and enables.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
See comments to Question 3.	

Likes 0	
Dislikes 0	

Response

See Question 3 response.

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC ("CEHE") appreciates the changes that the SDT made to the Draft-1. However, CEHE does not support Draft 2 because the majority of the recommendations and concerns submitted by CEHE in the last ballot period were not addressed in this revision.

Likes 0	
Dislikes 0	

Response

The SDT attempted to respond to all comments received from this posting.

Kinte Whitehead - Exelon - 3

Answer	No
Document Name	

Comment

Exelon concurs with comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

See EEI response.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
See EEI 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 submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
ITC supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
See EEI 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	
Changing "Applicable Facilities" to those defined in the BES definition can result in a change in the scope of the standard without modification of the standard if the BES definition changes. This does not align with analysis and identification of a facility as a reliability risk. The BES definition will likely always move in the direction to include smaller units at lower interconnection voltage and may not be based on reliability concerns. This change can	

increase the scope of Applicable Facilities without justification of the scope increase. We suggest the following changes to 4.2.1 to clarify the term "applicable Facility or Facility" using:

- 4.2.1.1 A BES generator with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater; or
- 4.2.1.2: BES generating "plant" at the common Point of Interconnection meaning the transmission (high voltage) side of the main generator step-up transformer where more than 75 MVA of aggregate generation has been collected connected at 100 kV and greater. Individual generating resources below the common point of interconnection are excluded.

Likes 0	
Dislikes 0	

Response

No change. Aggregations of smaller units can also be reliability risks. If the BES definition moves towards including smaller and smaller units, it will be because the NERC has decided that they provide enough of a risk to the transmission system that they need to be covered.

Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

I do not agree with the combining of Mod-26 and Mod 27. 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 wholly unique to each system, and models are wholly unique to each system. Testing may be staged separately, might be performed by different testing entities and model verification is evaluated for compliance for each on a separate basis. There is definitive clarity and management practicality in retaining separate MOD26 and MOD27 standards

Likes 0	
Dislikes 0	

Response

No change. Requirements within MOD-026-2 can be satisfied at different times or periodicity, meaning Requirement R2 can be completed at a different time as R3. Or they can be performed together.

Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
While the SDT made some clarifying improvements to the current draft, many of the issues identified in draft 1 remain. Please refer to the below comments.	
Likes 0	
Dislikes 0	
Response	
The SDT attempted to respond to all comments received from this posting.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Many of the technical concerns that were identified in first draft were not adequately addressed in second round.	
Likes 0	
Dislikes 0	
Response	
The SDT attempted to respond to all comments received from this posting.	
Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	

Comment	
The new requirement for EMT models represents a significant burden on Generator Owners. Additional models need to be developed, tested, and validated. There are limited resources available who can provide these services. Manufacturers may face challenges being able to provide PSCAD models for equipment that is no longer supported or in production.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with the comment. This was a consideration for the Implementation Plan timing. Additionally, see the exemptions for R6 in Attachment 1, Row 13.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

The SDT revision to 36 months is not sufficient.

Fundamentally, industry is resource limited as there aren't a sufficient number of EMT experts.

Industry must have at least 60 months to purchase software, train personnel and verify models. This is still an aggressive goal at 60 months.

NVE appreciates the changes the SDT made.

Key structural concerns included:

R1 still requires EMT models at all times without deferring to when the TP or PC requests them. While footnote 2 discusses the level of detail, it doesn't provide the TP with the flexibility to determine when EMT models are required.

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. NVE recommends that additional language be added to R1.1 and R1.2 to state EMT models "where determined and in accordance with the PC and TP joint model process in the requirements".

With regard to Part 1.2, NVE 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.

Clarifying "Facility". The NVE suggests the following changes to clarify:

4.2.1 For the purpose of this standard, the term "applicable Facility or Facility" subject to these requirements means:

4.2.1.1 A BES generator with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater; or

4.2.1.2: BES generating "plant" at the common Point of Interconnection meaning the transmission (high voltage) side of the main generator step-up transformer where more than 75 MVA of aggregate generation has been collected connected at 100 kV and greater. Individual generating resources below the common point of interconnection are excluded.

Likes 0	
Dislikes 0	

Response

See MRO NSRF response.

Casey Perry - PNM Resources - 1,3 - WECC

Answer	Yes
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF has no additional comments.	
Likes 0	
Dislikes 0	
Response	

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

PG&E agrees that Draft 2 is an improvement but feels there are additional items that need to be resolved which are identified in our responses to the remaining questions.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3	
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	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
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	
Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
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	

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.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
SPP suggests that the drafting team take into consideration revising Requirement R1 as well as the Technical Rationale to include language that shows that the MOD-032 Standard assists the PC in the data collection process to build the dynamic and EMT models. From our perspective, the proposed language suggests that the PC is using MOD-026-2 to assist in the model build, but this standard is more applicable to the TP which may create some confusion around the modeling process.	
Likes 0	
Dislikes 0	
Response	
No change. Entities are free to combine model requirements of MOD-32 and MOD-26-2 R1. Many details from data collected under MOD-32 are certainly used in building EMT models, however MOD-32 is not fully sufficient.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
The addition of "within 90 days of receiving a written request" in R1.6 is not a reliability based objective. NERC continues to add compliance administration to the requirements that have little to zero actual reliability benefits. NVE recommends no change or "in accordance with the TP process."	

Likes 0	
Dislikes 0	
Response	
No change. 90-day requirement is from the original standard. The risk is that if the TP has no requirement to send the GO the existing model in a timely manner, then the GO's timelines can become much longer. The risk here is that more time passes without the TP having a verified model.	
Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The new requirement for Electromagnetic Transient models requires significant effort and investment to meet. Obtaining PSCAD models for legacy equipment can be challenging or impossible depending on the level of support from the equipment manufacturer. Many of our windfarms are older than 10 years utilizing technology no longer in production.	
Likes 0	
Dislikes 0	
Response	
No change. There are exemptions for Requirement R6 in Attachment 1, Row 13.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Excitation Limiters and Protection System elements are not dynamic model elements; therefore, should not generically refer to them as elements of a dynamic model.	

The requirement continues to give the Transmission Planner and Planning Coordinator the ability to implement their own methods, requirements, processes, and acceptance criteria without constraints, boundaries, or need of consistency with other industry participants.

The requirement should establish a technical criterion as part of the standard revision and let the planners make local necessary adjustments as necessary. This will allow the GOs to have a say in what is required before the requirement becomes a mandate.

Likes 0	
Dislikes 0	

Response

No change. The SDT disagrees with this statement. Dynamic response is very much influenced and in some cases dictated by the limiters and protection elements.

PCs have the responsibility to be in line with best industry practices.

The TPs are able to define specific level of detail requirements if there are particular needs for an area specific study.

Greg Davis - Georgia Transmission Corporation - 1

Answer	No
Document Name	

Comment

It is unclear why the Planning Coordinator is being added to this requirement when the existing MOD-026 & 027 standards do not apply to this function.

The Operations time horizon does not appear appropriate for this type of long term coordination between the Transmission Planner and Planning Coordinator.

The time requirement for the TP to provide the dynamic model verification requirements and processes is not specified in R1.1 through R1.5.

The wording in R1.3 is unclear. It is also unclear why the PC is added to the parent requirement (R1) and not this sub-requirement (R1.3).

Likes 0	
Dislikes 0	

Response

No change. This is to ensure that the PC is part of the process, and that the PC gets the verified and validated models into the interconnection wide cases.

Changed to Long-Term Planning time horizon similar to R2-R6. The SDT expected that many of the requirements and processes of R1 would be updated almost annually.

No change. This is defined in the implementation plan for Requirement R1. R1 specifies that they “shall be made available” and adding more detail about this was unwarranted.

No change. Within R1.3, the TP shall have acceptance criteria, so they can ensure the model is usable and meets basic parameterization checks. This applies for both positive sequence and EMT models.

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

- R1 still requires EMT models at all times without deferring to when the TP or PC requests them. While footnote 2 discusses the level of detail, it doesn’t provide the TP with the flexibility to determine when EMT models are required. EMT models should only be required for resources which are specifically identified within Requirement R6, commissioned after the approval date of this Reliability Standard, and specifically identified by the TP and/or PC.
- 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. Southern Company recommends that additional language be added to R1.1 and R1.2 to state EMT models “where determined and in accordance with the PC and TP joint model process in the requirements”. Important requirement details cannot be left in the technical rationale.
- Southern Company continues to have 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. We suggest that 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.

- With regard to Part 1.2, we request that NERC or another 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.
- The addition of "within 90 days of receiving a written request" in R1.6 is not a reliability based objective. This adds compliance administration to the requirements that have little to zero actual reliability benefits. We recommend either no change or "in accordance with the TP process."

Likes 0	
Dislikes 0	

Response

NERC has (in multiple documents) discerned that it is important to collect EMT models before they are required for any individual project or study.

Change made to R1.2. Associated with Requirement R6.

Plants without PFR are exempt, as outlined Attachment 1.

EMT models must be user written, otherwise they are not useful. Standardized EMT models are available for passive elements but for the inverters/converters, they must be manufacturer written.

This 90-day requirement adds to reliability, if the GO/TO needs previous model data submitted to the TP.

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

Answer	No
Document Name	

Comment

ITC supports the comments submitted by EEI

ITC has the following additional comments:

ITC is concerned that for R1 the verification parameters must be jointly determined by the Transmission Planner and the Planning Coordinator. However, all of the studies will be performed by the TP who may be provided with a set of parameters that are a one size fits some within the PC

area and set for all TPs within the area and may not apply to all systems within the region. The PC could push for complicated and/or rigorous procedures if they are not actually doing the work. Since the actual validation work is done by the TP, except for those TP's who have delegated TP functions to the PC. Let the TP identify the validation parameters and unless the PC can justify why they are unacceptable and should be changed.	
Likes 0	
Dislikes 0	
Response	
See EEI response. This is to ensure that the PC is part of the process and that the PC gets the verified and validated models into the interconnection wide cases. PCs have the responsibility to be in line with best industry practices. Without coordination, different TPs within the same PC area may come up with different requirements that could make further studies by PCs on broader system challenging.	
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 submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
See EEI 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	
PGAE proposes an additional modification to Section 1.2 to help clarify what it applies to and when (mod/adds in bold): 1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail **for resources specifically identified within Requirement R6 only and commissioned after the approval date of this Reliability Standard.**	
Likes 0	
Dislikes 0	
Response	
Change made. The phrase "for Facilities identified within Requirement R6" was added to R1.2. No change. The fixed, specified date in Attachment 1, Row 13 (Requirement R6 exemption) will remain, so the language and date is specified in the standard. For now the proposed date is January 1, 2020.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	

Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon concurs with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
The terms used in Requirement R1, 1.3 should be supplemented with practical guidance. For example, additional language could be added to supplement the term “parameterization checks” to clarify that the term is meant to validate model parameters and settings against the actual field equipment. Similarly, additional language could be added to supplement the term “interoperability” to 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. and to indicate that both types of models (positive sequence and EMT models) should produce the same results when they operated different software platforms.

Regarding proposed Requirement R1.3, attempting to test initialization and interoperability in a full EMT case would require a fundamental change for Transmission Planners and the PC within ERCOT footprint. 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, CEHE suggests revising the proposed Requirement R1.3 to allow TPs to use the alternative method to validate the EMT models.

Likes 0	
Dislikes 0	

Response

No change. The SDT plans to improve the description for parameterization checks in the Technical Rationale. The terms are described in details in the Technical Rationale document. A Reliability Guideline for EMT Modeling as also recently been published.

No change. R1.3 does not require testing initialization and interoperability in a full EMT case. TPs and their PC will decide the verification requirement and process for a given system.

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

- Acceptable positive sequence dynamic Model list and level of detail should come from NERC ERAG /MMWG.
- Acceptable EMT Model list and level of detail should come from NERC ERAG /MMWG.

Likes 0	
Dislikes 0	

Response

TPs and PCs will jointly select a subset of approved positive sequence models that are applicable to their system.

EMT models must be user written, otherwise they are not useful. Standardized EMT models are available for passive elements but for the inverters/converters, they must be manufacturer written.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #2.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC Generator Working Group (GWG): Suggest adding to footnote 1 (and everywhere this footnote is) "existing" in front of documents and files	
Likes 0	
Dislikes 0	
Response	
No change. The footnote is meant to help distinguish between verification and validation.	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
Regional enforcement authorities lack the enforcement authority for inverter-based interconnected Generation utilities to get a Planning Coordinator or enforced the new modeling requirements.	
Likes 0	
Dislikes 0	
Response	
No change. The comment is related to a NERC Registration and Enforcement issue, and does not materially affect the language of MOD-026-2. As detailed in the applicability section, GOs, TPs, PCs, and some TOs are required to be compliant with the requirements of this NERC standard.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
AZPS does not agree that EMT modeling is necessary for dynamic model verification or that the SAR has provided sufficient justification for why it is needed. 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. Additionally, as written, R1 applies to both synchronous and inverter based resources. Currently there are no EMT models available to synchronous generation as it has not been determined to be useful. For these reasons, EMT models should not be required for synchronous resources, and only required for inverter based resources on an as needed basis such as if the model response does not match the actual response from a system event.	

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 as the example provided in the Technical Rationale is not comprehensive.

AZPS also supports the following proposed edits shown in bold submitted by EEI for Requirement 1, Part 1.2:

1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail **for resources specifically identified within Requirement R6 only, and commissioned after the approval date of this Reliability Standard, and specifically identified by the TP and/or PC**;

Likes 0	
Dislikes 0	

Response

NERC has (in multiple documents) discerned that it is important to collect EMT models before they are required for any individual project or study. Recommended practices and guidelines are not enforceable. The objective of this standard to ensure dynamic models are provided and verified in a consistent process.

Change made. EMT models are not required for synchronous generation. Added clarifier for R1.2 “for Facilities specifically identified within Requirement R6.”

SDT fully agrees that sound engineering judgement is an important part of any model validation exercise. Depending on the region and systems, TPs and PCs will detail the acceptance criteria (Requirement R1) as done in their joint verification requirement and processes.

See EEI 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

EMT models must be user written, otherwise they are not useful. Standardized EMT models are available for passive elements but for the inverters/converters, they must be manufacturer written.

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

Answer	No
Document Name	

Comment

R1.2 EMT models are not used by most Transmission Planners. This addition will add significant cost to generation owners. The EMT models requirement should be listed as optional and 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.). R1 should be modified to read:…The dynamic model verification requirements and processes shall be made available to the Generator Owner and Transmission Owner by the Transmission Planner, and include based on technical justification, the following:

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 MOD-027 standards.

Likes 0	
Dislikes 0	

Response

NERC has (in multiple documents) discerned that it is important to collect EMT models before they are required for any individual project or study.

TPs and PCs have the responsibility to be in line with best industry practices. A jointly developed verification requirements and process by TPs and PCs ensures that the models have the required details based on the requirements and characteristics of any given region or system. The intent is to ensure TPs and PCs will get the models needed to perform the required studies for their system.

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 these NERC Reliability Standards. BPA recommends a Reliability Guideline be developed, reviewed, and approved by the industry, PRIOR to making a sweeping change(s) pertaining to EMT Models in NERC Reliability Standards. This would allow industry an opportunity to fully understand the concepts of EMT model validation, outside of a FERC approved implementation plan.

Likes 0	
Dislikes 0	

Response

Reliability Guideline for EMT Modeling was published in March 2023. NERC has in multiple documents discerned that it is important to collect EMT models before they are required for any individual project or study.

Lindsey Mannion - ReliabilityFirst - 10

Answer	No
Document Name	

Comment

Requirement R1 addresses “dynamic model verification requirements and processes”, but Part 1.2 addresses EMT models, which are generally distinguished from “dynamic models”. While it may be possible to adjust the Requirement R1 language to be inclusive of dynamic models and EMT models, it seems cleaner to separate TP/PC EMT model verification requirements and processes into a separate requirement.

Likes 0	

Dislikes 0	
Response	
Change made. Made specific that R1.2 applies to EMT models for equipment identified in Requirement R6. While EMT models and positive sequence dynamic models are developed and used in different programs/platforms/studies, they should provide consistent results for a given system event. SDT is of the view that, by jointly developing verification requirements and processes for dynamic models, consistent responses will be obtained from both models.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
See MRO NSRF response.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI's Comments which state: EEI does not support the proposed language for R1 because (see comments below and suggested edits to Requirement R1 in boldface):	

· R1.2 is insufficiently clear as to EMT requirements. While Footnote 2 provides clarity, clarifications contained in footnotes are often missed. EEI suggests language that we believe generally aligns with SDT intent but is not contained in a footnote.

· R1.6 does not provide sufficient time for GOs and TOs to obtain models needed by the TP and PC. We suggest 180 days.

R1. Each Transmission Planner and its Planning Coordinator, shall jointly develop dynamic model verification requirements and processes. The dynamic model verification 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: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

1.1. Acceptable positive sequence dynamic models, format, and level of detail;

1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail **for resources specifically identified within Requirement R6 only, and commissioned after the approval date of this Reliability Standard, and specifically identified by the TP and/or PC**;

1.3. Acceptance criteria used by the Transmission Planner to determine disposition under 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;

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 database for an existing Facility owned by the Generator Owner or Transmission Owner within **180** days of receiving a written request

Likes 0	
Dislikes 0	

Response

R1.2 Change made. The phrase "for Facilities identified within Requirement R6" was added.

No change. A fixed, specified date in Attachment 1, Row 13 (Requirement R6 exemption) will remain, so the language and date is specified in the standard.

Regarding TP specified EMT requirement: Having an on-demand requirement for verified EMT models could be problematic. By having the TP define a need at any given time in the future, would create an emergent requirement for the GO to obtain an EMT model for an operational plant. For example, if a TP would require a verified EMT model in 2025, for a Facility commissioned in 2020, then the GO/TO would be considered a newly applicable Facility and have approximately one year to provide a verified EMT model to its TP. Whereas, with this approach all verified EMT models will need to be provided, if the Facility is commissioned after a specified date, which is a more straight forward approach. Obtaining verified EMT models is easier to achieve around the time of initial commissioning. Contracts that are in place with the equipment manufacturer allow for the delivery of a verified EMT model. Once the OEM is no longer under contract and more time passes, it becomes more difficult to obtain the required information. As more time passes from commissioning date, the risk increases that an OEM may no longer support the existing equipment, OEM personnel familiar with the technology or installation may have left the company, or the OEM may no longer be in business.

R1.6 Change made. This process is defined by the TP/PC. The TP would provide model data (from the TP's existing database) to the GO/TO, upon receiving a request by the GO/TO.

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	No
Document Name	

Comment

The addition of "within 90 days of receiving a written request" in R1.6 is not a reliability based objective. NERC continues to add compliance administration to the requirements that have little to zero actual reliability benefits. The MRO NSRF recommends no change or "in accordance with the TP process."

Likes 0	
Dislikes 0	

Response

No change in timing. 90-day requirement is from the original standard. The risk is that if the TP has no requirement to send the GO the existing model in a timely manner, then the GO's timelines to update their model can become much longer.

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

Answer	No
Document Name	
Comment	
WEC Energy Group supports both the MRO NSRF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
See MRO NSRF and EEI responses.	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM Resources recommends the Planning Coordinator be removed from requirement R1. MOD-032 addresses modeling requirements and communication of models to the Planning Coordinator. Given the confidentially around EMT modeling it will be difficult to provide EMT models to a Planning Coordinator. With the limitations of EMT modeling on large system, it probably doesn't make sense to require both Planning Coordinator and Transmission Planner to keep EMT modeling data.	
Likes 0	
Dislikes 0	
Response	
No change. The SDT believes that TP should be jointly developing this model verification requirements and processes. The requirements are worded such that the TP can take the lead in this process. Verified models shall be sent to the TP and they determine the disposition per Requirement R1.3.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No

Document Name	
Comment	
The addition of “within 90 days of receiving a written request” in R1.6 is not a reliability based objective. NERC continues to add compliance administration to the requirements that have little to zero actual reliability benefits. The MRO NSRF recommends no change or “in accordance with the TP process.”	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
No change. 90-day requirement is from the original standard. The risk is that if the TP has no requirement to send the GO the existing model in a timely manner, then the GO’s timelines to update their model can become much longer.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
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	
No change. The SDT believes this language reduces the compliance obligation to track the requests and responses of this information. The modeling requirements and processes can be public posted on a website, an internal portal, or be an internal process for vertically integrated company. Adding the PC coordination is necessary since models need to have a basic level of compatibility. MOD-026 and MOD-032 coordination between TP/PC can be achieved similarly. The level of initialization tests and criteria would be specified by the TP under R1.3.2. Model interoperability is discussed in the Technical Rationale and industry practice. Change made to R1.2. "Acceptable electromagnetic transient (EMT) models, format, and level of detail for Facilities specifically identified within Requirement R6." If IBR Facilities are added to the TPs footprint then EMT models would be required. There is an increasing amount of IBR Facilities being added to the BES. The justification for adding EMT models in MOD-026 is discussed in the Technical Rationale and Initial Ballot Consideration of Comment. See Technical Rationale for Requirement R6. EMT models are needed to understand the large signal disturbance response of an IBR Facility. NERC has published multiple disturbance reports, including the Odessa Disturbance Report of May and June 2021 (page 22-31), and 2021 California Solar PV Disturbances of June and August 2021 (page 20- 33). In both reports, NERC raised significant concerns regarding positive sequence modeling practices and the need for industry to verify and validate the accuracy of the models being used for reliability studies. From the Odessa Disturbance Report, most of the causes of solar PV reduction identified in this event and past events analyzed by NERC cannot be properly represented in positive sequence dynamic models. High quality, vendor-specific EMT models are required to identify these causes of tripping.	
Brian Lindsey - Entergy - 1	
Answer	No

Document Name	
Comment	
Why do the dynamic model verification requirements and processes need to be jointly developed with the planning coordinator since the transmission planner is solely responsible for the verification studies?	
Likes 0	
Dislikes 0	
Response	
Adding the PC coordination is necessary since models need to have a basic level of compatibility. MOD-026 and MOD-032 coordination.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Please refer to item 1) comment provided in Q1.	
Likes 0	
Dislikes 0	
Response	
See Question 1 response.	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
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 achieved 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 operated 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

The intention of adding the PC coordination is to ensure models have a basic level of compatibility; rather, than checks and balances to verify modeling accuracy. Even if the TO and TP are the same entity, these requirements improve accuracy by requiring cross-departmental, documented model verification.

The terms in R1.3 are defined in the technical rationale.

Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
While the SRC generally agrees with the revised language, we have provided some suggestions for R1 under the response to Question 9, below.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	

AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF supports the proposed Requirement R1 modifications.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation agrees with the proposed language, however feels the 90 day requirement under R1.6 is duplicative to R8. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	
Response	
These are different. Under R1.6 the TP provides existing models to help the TO/GO perform their model verification. Under R8 the TP reviews the model verification materials provided by the TO/GO.	
Kristine Howie - Kristine Howie Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
Answer	Yes
Document Name	
Comment	
Constellation agrees with the proposed language, however feels the 90 day requirement under R1.6 is duplicative to R8. Kristine Howie Behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
These are different. Under R1.6 the TP provides existing models to help the TO/GO perform their model verification. Under R8 the TP reviews the model verification materials provided by the TO/GO.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports NAGF comments.	
Likes 0	
Dislikes 0	

Response	
See NAGF response.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
BC Hydro suggests the term “90 days” in R1.6 is changed to “90 calendar days” for clarity and consistency with the language used in other Requirements.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees and made the change.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP has no objections to the language proposed for R1.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	

Answer	Yes
Document Name	
Comment	
The Impacts to R1.2 requiring EMT models will likely impact TP staff in the future. As of now the GO for IBRs are responsible for the EMT models, however interconnect request may require Avista TP assessment and validation as part of the interconnect assessment. Also in the future if we build wind as a GO or take over and existing wind farm as the new GO upon contract expiration and/or termination, significant SME resources will be required to meet this new EMT requirement.	
Likes 0	
Dislikes 0	
Response	
No change. Agreed, your comments are considerations that were made in the Implementation Plan.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
The Impacts to R1.2 requiring EMT models will likely impact TP staff in the future. As of now the GO for IBRs are responsible for the EMT models, however interconnect request may require Avista TP assessment and validation as part of the interconnect assessment. Also in the future if we build wind as a GO or take over and exiting wind farm as the new GO up[on contract expiration and/or termination, significant SME resources will be required to meet this new EMT requirement.	
Likes 0	
Dislikes 0	
Response	
Understood. The justification for adding EMT models in MOD-026 is discussed in the Technical Rationale and Initial Ballot Consideration of Comment. See Technical Rationale for Requirement R6. EMT models are needed to understand the large signal disturbance response of an IBR Facility. NERC has	

published multiple disturbance reports, including the Odessa Disturbance Report of May and June 2021 (page 22-31), and 2021 California Solar PV Disturbances of June and August 2021 (page 20- 33). In both reports, NERC raised significant concerns regarding positive sequence modeling practices and the need for industry to verify and validate the accuracy of the models being used for reliability studies. From the Odessa Disturbance Report, most of the causes of solar PV reduction identified in this event and past events analyzed by NERC cannot be properly represented in positive sequence dynamic models. High quality, vendor-specific EMT models are required to identify these causes of tripping.

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC	
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	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ryan Strom - Buckeye Power, Inc. - 5 - RF

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments.	
Likes 0	
Dislikes 0	
Response	

Josh Combs - Black Hills Corporation - 3	
Answer	
Document Name	
Comment	
Although BHC agrees with the proposed, it is felt a potential for exceptions on older units may be needed depending upon the criteria of a model as specified by the TP. This may result in a need for a longer implementation if all Facilities are expected to meet the criteria.	

Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
Although BHC agrees with the proposed, it is felt a potential for exceptions on older units may be needed depending upon the criteria of a model as specified by the TP. This may result in a need for a longer implementation if all Facilities are expected to meet the criteria.	
Likes 0	
Dislikes 0	
Response	
For older units for which data may be unobtainable, R6.2 is satisfied with documentation explaining the reason.	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Although BHC agrees with the proposed, it is felt a potential for exceptions on older units may be needed depending upon the criteria of a model as specified by the TP. This may result in a need for a longer implementation if all Facilities are expected to meet the criteria.	
Likes 0	
Dislikes 0	
Response	

For older units for which data may be unobtainable, R6.2 is satisfied with documentation explaining the reason.

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
Although BHC agrees with the proposed, it is felt a potential for exceptions on older units may be needed depending upon the criteria of a model as specified by the TP. This may result in a need for a longer implementation if all Facilities are expected to meet the criteria.	
Likes 0	
Dislikes 0	
Response	
For older units for which data may be unobtainable, R6.2 is satisfied with documentation explaining the reason.	

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*.**

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
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	
No change. It should be understood that modeling data of protection and limiting elements that are not in service (as the first sentences in R2 and R3 state that only "in-service" equipment is in scope) are not subject to these requirements.	
Nazra Gladu - Manitoba Hydro – 1	
Answer	No
Document Name	
Comment	
It looks like the SDT added more relay elements to the requirement R2.3. MH previously mentioned that this requirement is too prescriptive and some of these relay models may not be available in standard library models developed for positive sequence simulation tools. We believe it is up to	

the TP/PC (based on their experience) to determine the required minimum modeling requirements and level of the modeling details required for the protection and control.

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/PC.

Does not encourage dialogue between entities to ensure a cost-effective manner to meet the TP/PC required modeling details. Adding more details such as more protection elements to the minimum modeling requirements without considering the actual TP/PC modeling details requirements, type of studies and studies issues is not the right way to go. It should be left up to the TP/PC to communicate to the generator and transmission owners the minimum modeling requirements to address their concerns and needs.

Likes 0	
Dislikes 0	

Response

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD

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 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field.

Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

Requirement R2 2.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating dynamic behavior of control systems.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF.	
Larry Brusseau - Corn Belt Power Cooperative - 1 – MRO	
Answer	No
Document Name	
Comment	
Requirement R2 2.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating dynamic behavior of control systems.	
Likes 0	
Dislikes 0	
Response	
In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.	

Jamie Monette - Allete - Minnesota Power, Inc. – 1	
Answer	No
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF.	

Thomas Foltz - AEP – 5	
Answer	No
Document Name	
Comment	
AEP does not agree with the inclusion of models representing Protection Systems of synchronous generating units as stated in R2.3 and R3.3: 1) MOD-032 allows the TP and PC to request protection system data and modeling if it is deemed necessary. MOD-026-2 is supposed to be a model verification/validation standard. It should not be expanded into a data collection standard and thereby not only cause compliance duplication with MOD-032, but force collection of data that the TP and PC may well regard as unnecessary. Validation (as "validation" is defined in the standard) of protection function modeling is already acknowledged as not feasible. As with the collection of any and all data, the collection of protection modeling data implies its verification and thus verification may and should be left to MOD-032. 2) R2.3 and R3.3 introduce further compliance duplication by requiring the Generator Owner to verify generator protection models whose settings data is already verified through the scope of obligations within PRC-019, PRC-024, PRC-026, and PRC-027. When considered in their entirety, these standards, in requiring verification of protection system settings against certain stipulated criteria designed to address conditions and events that could negatively impact BES reliability, serve to meet the SDT's intent. 3) In distinct contrast to IBR protection and control as seen in recent disturbance event tripping and runback, the requested protection function	

modeling of synchronous generation has not been found to worsen disturbance events in any significant way. Moreover, also in distinct contrast to IBR protection and control, synchronous generation protection has accumulated a great deal of theory and experience in application over many decades. This has eliminated nearly all risk in its application. As long as setting coordination and verification is assured via these other standards, there is no meaningful gain to reliability in requiring the collection of this data in MOD-026-2.

Therefore, we do not believe the proposed inclusion of protection model data verification and collection in MOD-026-2 would result in meaningful contribution to improving the reliability of the BES.

4) Further 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. As a limiter, it would have an inverse time characteristic likely to extend beyond normal simulation durations.• Field overcurrent – Backup to the over-excitation limiter/maximum excitation limiter (OEL/MXL). It is not necessary to model the trip function as long as the limiter is active.

• Loss of field – No precedent for an excitation equipment failure contingency exists in a standard or in past practice to warrant modeling of this protection. Loss-of-field protection is coordinated with the UEL/MEL for out-of-step operation and loss of excitation due to equipment failure. It is not necessary to model the trip function as long as the limiter is active.

• Out-of-step – Not universally applied on all synchronous units. There are other more straightforward means to remove unstable units from simulations (there is a check box option in PSS/E, for example). It is not necessary to add this model in simulations.

• Volts per hertz – Generally, a limiter function is coordinated with trip and in many cases the trip function is active only while the unit is off-line in start-up or shutdown. With possible exception of UFLS studies where low frequency conditions are intentionally produced, it is not generally necessary and there are time-based V/Hz constraints on UFLS program settings in PRC-006 to avoid V/Hz limiter activation. Thus, this protection is unnecessary to model. There is no limiter function model in PSS/E; it is trip or monitor only.

• Phase-distance – AEP is unsure why this has been added in Draft 2, and requests insight from the SDT as to their motivations for doing so.

AEP disagrees with the inclusion of “prime mover” within 2.3, as none of the devices specified in 2.3 would directly trip the prime mover.

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service. Under R2.4, enabled Protection Systems and limiters are not required to have "validation" using a staged test or measured disturbance.	
Lindsey Mannion - ReliabilityFirst – 10	
Answer	No
Document Name	
Comment	
RF recommends minimum dynamics modeling requirements (including any necessary minimum Protection System modeling requirements) be specified in MOD-032 Attachment 1. The TP or PC can request other necessary modeling information as needed, but it is useful for Registered Entities and Compliance Enforcement Authorities if MOD-032 Attachment 1 provides a one-stop shop for the ERO-wide minimum modeling requirements.	
Likes 0	
Dislikes 0	
Response	
In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
R3.3 is covered under NERC Reliability Standards PRC-019 and PRC-024. BPA believes adding R3.3 is redundant.	

Likes 0	
Dislikes 0	

Response

R3.3 is verification of frequency and overspeed protection settings while PRC-024 restricts frequency protection settings only. These are not completely overlapping objectives. PRC-019 is coordination between voltage-related protection and limiting elements and does not address frequency or overspeed protection.

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

Answer	No
Document Name	

Comment

The limiter models in PSSe 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 that simulated response of limiter models do not need to match test data for limiters.

a. 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	
Validation (via staged testing) of excitation limiters by comparison of simulations to field test recordings has been removed from Draft 2 and verification of limiter settings only is now required. This change was done by moving limiters from R2.2 to R2.3 and the fact that R2.4 only requires validation of modeling in R2.2. In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	
Rewrite section 2.3 to include the added words in bold: "Model(s) representing enabled excitation limiters and **model(s) representing** enabled Protection Systems that directly trip the prime mover or generator/synchronous condenser. Protection Systems that shall be modeled include phase over- and undervoltage, stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, loss of field, out-of-step, phase-distance, and volts per hertz protection; and" As currently written with the “and” between “excitation limiters” and “enabled Protection Systems,” it can be interpreted that only excitation limiters that directly trip the prime mover need to be modeled. Excitation limiters should always be modeled.	
Likes 0	
Dislikes 0	
Response	
Change made. The SDT agrees with the possibility of misinterpretation and has revised the language of R2.3 accordingly.	
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	
No change. Since the GO owns the equipment, the GO must be the entity that validates the model. The TP cannot run tests on and validate a model of someone else's equipment. The TP can only check the model for reasonableness and usability based on what is defined by the TP in Requirement R1.	
Marcus Bortman - APS - Arizona Public Service Co. – 6	
Answer	No
Document Name	
Comment	
For Requirement 2, Part 2.3 and Requirement 3, Part 3.3, AZPS requests that the SDT add clarification regarding what is meant by direct trip of the prime mover, including clarification of which trips are to be addressed or by providing diagrams such as those included in PRC-025 and PRC-027. For Requirement 2, Part 2.3 and Requirement 3, Part 3.3 AZPS does not agree that modeling limiters and protection systems for prime movers for generator/synchronous condensers should be included as PRC-019 already ensures that limiters and protection systems are coordinated to ensure they operate as intended and are adequate for the intended application. For this reason, creating generator protection models from protection settings would still be a significant amount of work with very little reliability benefit.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	

A prime mover trip (turbine trip) is generally well defined within industry - for example, IEEE C37.102, the Guide for AC Generator Protection, includes this terminology, as does the NERC Considerations for Power Plant and Transmission System Protection Coordination. The SDT believes that additional definition of the term "trip the prime mover" is therefore unnecessary.

For further insight, the purpose of adding prime mover trips is to include the applicable relay elements that use "sequential tripping"- tripping the prime mover and subsequently opening the generator breaker on reverse power – which is a common tripping scheme for large steam turbines.

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

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

Answer	No
Document Name	

Comment

Requirement Subpart R2.3 and R3.3 should not require models to contain limiters and protection settings. This information is already provided in PRC-019, PRC-024, and PRC-026, and is not necessary for validating dynamic behavior of control systems. If these subparts to R2 and R3 are kept in the next draft, then more detailed justification and rationale for how protection settings are necessary should be provided in the Technical Rationale.

Likes 0	
Dislikes 0	

Response

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

Kristine Howie - Kristine Howie On Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie

Answer	No
Document Name	
Comment	

Constellation appreciates the clarification that models do not need to be completed simultaneously, however, does not agree with the expanded requirements for 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.

Kristine Howie on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

Alison MacKellar - Constellation – 5

Answer	No
Document Name	
Comment	

Constellation appreciates the clarification that models do not need to be completed simultaneously, however, does not agree with the expanded requirements for 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.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response	
In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports the comments submitted by LPPC. Tacoma Power is concerned on the potential impact of adding new protection elements to MOD-026 for synchronous generation. Existing modeling software may be capable of modeling these new protection elements, but these models are untested and will need to be tested to have full confidence in the results. Additionally, these models are not currently used in any WECC cases, and would require significant coordination throughout the ERO to standardize the cases. In order to understand the benefit and purpose of modeling protection elements for synchronous generation, Tacoma Power requests additional justification from the SDT describing the benefits of this work and why the PRC Standards are not sufficient. It would take a significant time investment to provide the setting data and translate it into a format that would be usable for these models.	
Likes 0	
Dislikes 0	
Response	
In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie – 1	
Answer	No
Document Name	
Comment	

Recommend the following language modification to clarify that asset owners (not interconnecting TOs) are responsible to provide the verified models.

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, *the asset owner (Generator Owner or Transmission Owner)* shall provide a verified positive sequence dynamic model(s), with associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1.

At section 3.3, "Protection Systems that shall be modeled include over- and under-frequency elements" seem redundant with "model(s) representing enabled prime mover over- and under-speed trip functions". Remove redundancy or provide more information to differentiate both requirements.

At section 3.4, a note explaining what "validation" means should be added, similar to section 2.4.

Likes 0	
Dislikes 0	
Response	

Change made. R2-R6 updated to say "asset owner", if applicable. Since the Generator Owner and Transmission Owner are identified in the Applicability Section, it should be clear that they are the facility owners and it should not be necessary to introduce the term "asset owner" here. Per Applicability Section 4.1.4, the Transmission Owner is only a Functional Entity when they own Facility listed in Section 4.2.4 or 4.2.5.

Over- and under-frequency elements are distinct from over- and under-speed trip functions. Off-nominal frequency protection are typically applied to protect turbine blade damage, whereas over-speed is often applied to protect against sudden load rejection.

The SDT agrees with the third suggestion and has added the footnote to R3.4 accordingly.

Cyntia Doré - Hydro-Qu?bec Production - 5 – NPCC	
Answer	No

Document Name	
Comment	

At section 3.3, "Protection Systems that shall be modeled include over- and under-frequency elements" seem redundant with "model(s) representing enabled prime mover over- and under-speed trip functions". Remove redundancy or provide more information to differentiate both requirements.

At section 3.4, a note explaining what "validation" means should be added, similar to section 2.4.

Recommend the following language modification to clarify that asset owners (not interconnecting TOs) are responsible to provide the verified models.

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, *the asset owner (Generator Owner or Transmission Owner)* shall provide a verified positive sequence dynamic model(s), with associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1.

Likes 0	
Dislikes 0	

Response

No change. Over- and under-frequency elements are distinct from over- and under-speed trip functions. Off-nominal frequency protection may be applied to prevent shaft fatigue whereas over-speed is often applied to protect against sudden load rejection.

Change made. The SDT agrees with the suggestion and added the footnote to R3.4 accordingly.

Change made. R2-R6 updated to say "asset owner", if applicable. Since the GO and TO are identified in the Applicability Section, it should be clear that they are the facility owners and it should not be necessary to introduce the term "asset owner" here.

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	
Comment	

CEHE disagrees with including the proposed Requirements R2.3 and R3.3 as minimum modeling requirements. The TP and its PC should jointly determine the required minimum modeling requirements and level of the modeling details as stated in Requirement R1.1. If the TP and PC 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 determined by the TP and PC.

Likes 0	
Dislikes 0	

Response

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

Kenya Streeter - Edison International - Southern California Edison Company – 6

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

See EEI 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 indicates the models identified in Requirements R2.3 and R3.3 should only be required if they are required by the Transmission Planner and simplified. Please see the example of proposed modifications to the R2 language below (mod/adds in bold):

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) with associated parameters, and accompanying information that represents the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1. The verified model(s) and accompanying information shall include at a minimum the **following from 2.1-2.3, and if applicable the model(s) listed in 2.4 as determined to be required by the Transmission Planner in R1:** [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2.1. Manufacturer, model number (if available), and type of generator/synchronous condenser, excitation system hardware, and Protection System(s) specified in Part 2.3;

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

2.3**. Validation of the positive sequence dynamic model(s) of Part 2.2 response using the recorded response for a dynamic reactive power or voltage event from either a staged test or a measured system disturbance.**

2.4. Model(s) representing enabled excitation limiters and enabled Protection Systems that directly trip the prime mover or generator/synchronous condenser. Protection Systems that shall be modeled include phase over- and undervoltage, stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, loss of field, out-of-step, phase-distance, and volts per hertz protection.

The above should also be applied to R3 in a similar manner.

Likes 0	
Dislikes 0	

Response

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance,

and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

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	
Requirement R2 2.3 and R3 3.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating the dynamic behavior of control systems. Clarify in R2 that it is for excitation/voltage control/var control systems and in R3 that it is for frequency/MW/governor control systems. Reading R2 and R3 alone without the sub parts of each make it difficult to understand what dynamic behavior is to be modeled.	
Likes 0	
Dislikes 0	
Response	
In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service. Change made. The SDT agrees with your second comment and has revised the headers accordingly.	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. – 6	
Answer	No
Document Name	
Comment	

R2 2.3 covering protection system modeling is crossing over ground already in PRC standards, PRC19 and PRC24. This is also requiring contributed input from yet other new entities not previously involved in MOD-026 compliance.

Likes 0	
Dislikes 0	

Response

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

Joseph McClung - JEA - 1, Group Name LPPC

Answer	No
Document Name	

Comment

Large Public Power Council (LPPC) disagree with the proposed language. LPPC members have expressed the view that Requirement Subpart R2.3 and R3.3 should not require models to contain limiters and protection settings. They point out that this information is already provided in PRC-019, PRC-024, and PRC-026, and is not necessary for validating dynamic behavior of control systems. If these subparts to R2 and R3 are kept in the next draft, then more detailed justification and rationale for how protection settings are necessary should be provided in the Technical Rationale.

Likes 3	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre; Austin Energy, 6, Mrini Imane; JEA, 3, Williams Marilyn
Dislikes 0	

Response

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

John McCaffrey - American Public Power Association - 4 - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The American Public Power Association (APPA) disagrees with the proposed language. APPA members have expressed the view that Requirement Subpart R2.3 and R3.3 should not require models to contain limiters and protection settings. They point out that this information is already provided in PRC-019, PRC-024, and PRC-026, and is not necessary for validating dynamic behavior of control systems. If these subparts to R2 and R3 are kept in the next draft, then more detailed justification and rationale for how protection settings are necessary should be provided in the Technical Rationale.	
Likes 0	
Dislikes 0	
Response	
In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.	

Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Requirement Subpart R2.3 and R3.3 should not require models to contain limiters and protection settings. This information is already provided in PRC-019, PRC-024, and PRC-026, and is not necessary for validating dynamic behavior of control systems. If these subparts to R2 and R3 are kept in the next draft, then more detailed justification and rationale for how protection settings are necessary should be provided in the Technical Rationale.	
Likes 0	
Dislikes 0	
Response	

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

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

No change. It is true that R2 and R3 follow the same nearly identical pattern, but the distinction between excitation and governing is significant and the SDT believes they should be retained in separate requirements. This also helps if the GO/TO want to perform activities of R2 and R3 on separate schedules.

Headers have been added to highlight the distinction.

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee

Answer	No
Document Name	

Comment

In R2.3, if a generator doesn't have one of those protection devices then there should be no model requirement

Likes 0	

Dislikes 0	
Response	

No change. From the text of the main requirement R2, it should be understood that equipment not in-service is not subject to any of the R2 sub-parts. The terms “in-service” and “enabled” both make this distinction.

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

Answer	No
Document Name	
Comment	

Limiters and Protection are not dynamic model elements. PRC standards’ established limitations should generically be used by the TP to establish modeling boundaries. The absence of a relay protection trip does not make every non-trip operating region acceptable for a generator. PRC protective relay setting criteria have pushed boundaries beyond conservative protection limits for increased system reliability. If planning criteria has no restrictions other than the limits of an individual generator’s protective trip, it goes too far. Rather than establishing operating boundaries based upon the Generator trip settings, Transmission Planners need to understand and implement planning criteria consistent and lower than PRC protective relay setting boundaries. For example, there is no technical reason to make plans for operation outside the no-trip boundaries of PRC-024, regardless of where the generator protection is set.

To achieve 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.

Likes 0	
Dislikes 0	
Response	

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

Planning criteria are already coordinated with voltage and frequency operating boundaries of generation as much as such coordination makes sense, specifically, the coordination between PRC-006 and PRC-024. However, conditions and events in a power system are not restricted to planning criteria and if generation facilities can tolerate more extreme voltage and frequency conditions than required by standards without risk of damage, it should be permissible for them to do so as a benefit to system reliability. The events involving IBR ride-through failure have shown that IBR generation protection is unnecessarily encroaching into conditions and events well within long-standing planning criteria. Moreover, it should not be thought out of the domain of planning to analyze more extreme conditions and events. Also, TPs cannot be responsible for verified and validated models of equipment they don't own. The facility owners must assume that responsibility.

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	No
Document Name	
Comment	
SMUD and BANC support the comment of LPPC.	
Likes 0	
Dislikes 0	
Response	
See LPPC response.	
Dwanique Spiller - Berkshire Hathaway - NV Energy – 5	
Answer	No
Document Name	
Comment	
Requirement R2 2.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating dynamic behavior of control systems.	

Likes 0	
Dislikes 0	

Response

In response to several comments on synchronous generation protection elements in R2.3, the SDT has removed stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, and loss of field. Remaining in R2.3 are phase over- and under-voltage, out-of-step, phase-distance, and volts per Hertz which the SDT believes could be activated during severe system transient events and, therefore, verified modeling of these should be required wherever they are present and in service.

Michael Dieringer - Austin Energy – 3

Answer	No
Document Name	

Comment

Austin Energy supports LPPC comments

Likes 0	
Dislikes 0	

Response

See LPPC response.

Tony Hua - Austin Energy – 4

Answer	No
Document Name	

Comment

Austin Energy supports LPC comments

Likes 0	
Dislikes 0	

Response	
See LPPC response.	
Constantin Chitescu - Ontario Power Generation Inc. – 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
See NPCC response.	
Casey Perry - PNM Resources - 1,3 – WECC	
Answer	Yes
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes

Document Name	
Comment	
FirstEnergy supports the revised language in R2 and R3.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
BC Hydro suggests that the wording in Requirement R2 Part 2.3 and Requirement R3 Part 3.3 be adjusted to include enabled Protection Systems that trip the prime mover or generator/synchronous condenser via lockout or auxiliary tripping relays. This is also consistent with PRC-005-6 Section 4.2 Facilities. Please see R2 Part 2.3 suggested wording for drafting team's consideration: "Model(s) representing enabled excitation limiters and enabled Protection Systems that trip the prime mover or generator/synchronous condenser *either directly or via lockout or auxiliary tripping relays."*	
Likes 0	
Dislikes 0	
Response	
Change made. This revision has been made to R2.3.	
David Jendras Sr - Ameren - Ameren Services – 3	
Answer	Yes
Document Name	

Comment	
Ameren agrees with and supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Dave Krueger - SERC Reliability Corporation – 10	
Answer	Yes
Document Name	
Comment	
On behalf of the SERC GWG, suggest clarifying that R2 is for excitation systems and R3 is for governor controls	
Likes 0	
Dislikes 0	
Response	
Change made. The SDT expanded the requirement section headers in response to your suggestion.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF supports the proposed Requirements R2 and R3 modifications.	
Likes 0	

Dislikes 0	
Response	
Kinte Whitehead - Exelon – 3	
Answer	Yes
Document Name	
Comment	
Exelon concurs with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Daniel Gacek - Exelon – 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI 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 submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
ITC supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	

AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Brian Lindsey - Entergy – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC – 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3	
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	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Buckeye Power, Inc. - 5 – RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
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	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation – 6	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation – 1	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation – 3	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	

Recommend the following language modification to clarify that asset owners (not interconnecting TOs) are responsible to provide the verified models. 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, *the asset owner (Generator Owner or Transmission Owner)* shall provide a verified positive sequence dynamic model(s), with associated parameters, and accompanying information that represents the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Change made. R2-R6 updated to say “asset owner”, if applicable.	
Imane Mrini - Austin Energy – 6	
Answer	
Document Name	
Comment	
Austin Energy supports LPPC comments. Austin Energy. Segments 1,3,4,5,6	
Likes 0	
Dislikes 0	
Response	
See LPPC 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.***

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	
Comment	

OPG supports NPCC Regional Standards Committee's comments.

Likes 0	
Dislikes 0	
Response	

Change made. R2-R6 updated to say "asset owner", if applicable.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	
Comment	

Large System Disturbance Definition:

NVE suggests, the SDT better define what is a large system disturbance. NVE 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).

NVE suggests adding technical rationale language clarifying that large signal performance validation or verification could be completed via simulations. Requirement R4 4.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating dynamic behavior of control systems. R5 5.3: Same as comments for R2 2.3.	
Likes 0	
Dislikes 0	
Response	
Change made. See footnote for large signal disturbance in R6. See Technical Rationale describing large signal disturbance. It should be understood that the intent of MOD-026-2 is to provide <u>dynamic models</u> for limiter and protection settings. Meanwhile, PRC-019 and PRC-024 pertain to <u>coordination</u> of the relays. The deliverables of all of the Standards are independent. That is to say, a relay can be accurately modeled regardless of whether it is properly coordinated per PRC-019 or PRC-024. Even if a relay is properly coordinated, there will always be a system event of magnitude that forces the unit out of its operational capability and results in a unit trip from protection settings. This performance can only be captured if protection elements are modeled.	
Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The SDT should consider revising this to limit the relay modeling scope to only those relays that are appropriate for the positive sequence modelling and not limiters or protection settings. An additional concern is different expectations of different TPs and how that is communicated to the GOs.	
Likes 0	
Dislikes 0	
Response	

The SDT has limited the relay modeling scope to be that specific to voltage and frequency elements.

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Regarding R4.2, 4.4, 5.2, and 5.4, the addition of limiters and protection into models is repeating the purpose of PRC-019 and PRC-024. It would be better to come up with another specific requirement for the TP to use this existing information.	
Likes 0	
Dislikes 0	
Response	
It should be understood that the intent of MOD-026-2 is to provide dynamic models for limiter and protection settings. Meanwhile, PRC-019 and PRC-024 pertain to coordination of the relays. The deliverables of all of the Standards are independent. That is to say, a relay can be accurately modeled regardless of whether it is properly coordinated per PRC-019 or PRC-024. Even if a relay is properly coordinated, there will always be a system event of magnitude that forces the unit out of its operational capability and results in a unit trip from protection settings. This performance can only be captured if protection elements are modeled.	
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	

While it is true that the language is very similar between R4 and R5, the control loops and associated output (voltage & reactive power vs active power) are, practically speaking, independent in their operation for the purpose of positive sequence modeling. Similarly, FERC requirements associated with these loops (e.g. FERC Order 842) are also independent. Therefore the SDT sees that independence of the requirement is critical to ensure that the GO is not burdened to perform compliance tasks which are not associated with the performance of a given control loop.

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	

Requirements R4 4.1 and R5 5.1: Should not require software/firmware version of IBR and PPC. This information is not typically easily obtainable and is not critical to validating dynamic response of equipment. This detail has not been shown to be critical in the successful modeling of digital excitation systems used for synchronous generator automatic voltage regulation or for digitally based turbine control systems and frequency regulation control systems.

Requirement R4 4.3 and R5 5.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating the dynamic behavior of control systems.

Likes 0	
Dislikes 0	
Response	

The latest software/firmware version numbers would only need to be provided when the model and accompanying information is updated in accordance with R4/R5. If the software/firmware is updated for IBR units, but the dynamic response characteristic is not changed, then Requirement R7 would not apply. Requirement R7 only applies when the change to in-service equipment alters the equipment response characteristic.

It should be understood that the intent of MOD-026-2 is to provide dynamic models for limiter and protection settings. Meanwhile, PRC-019 and PRC-024 pertain to coordination of the relays. The deliverables of all of the Standards are independent. That is to say, a relay can be accurately modeled regardless of whether it is properly coordinated per PRC-019 or PRC-024.

Even if a relay is properly coordinated, there will always be a system event of magnitude that forces the unit out of its operational capability and results in a unit trip from protection settings. This performance can only be captured if protection elements are modeled.

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
This may have been an error, as EEI indicated that they agree with the proposed language in R4 & R5. EEI does request definition of "Large Signal Disturbance". Change made. See footnote for large signal disturbance in R6. See Technical Rationale describing large signal disturbance.	

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE recommends that the minimum dynamics modeling requirements (including any necessary minimum modeling requirements for enabled protections and limiters) be specified in MOD-032 Attachment 1. The TP or PC can request other necessary modeling information as needed, but it is useful for Registered Entities and Compliance Enforcement Authorities if MOD-032 Attachment 1 provides a one-stop shop for the ERO-wide minimum modeling requirements.	
Likes 0	
Dislikes 0	
Response	

The justification of adding Protection System to verified models is outlined in the Technical Rationale. By including model(s) representing the limiter and Protection System in MOD-026-2, the models and associate parameters must be verified to represent in-service equipment on the Facility.	
Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC	
Answer	No
Document Name	
Comment	
Recommend the following language modification to clarify that asset owners (not interconnecting TOs) are responsible to provide the verified models. 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, *the asset owner (Generator Owner or Transmission Owner)* shall provide a verified positive sequence dynamic model(s), with associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Change made. Request to clarify that asset owners are responsible to provide verified models, with modification to wording in R4 (and assumed R5).	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Recommend the following language modification to clarify that asset owners (not interconnecting TOs) are responsible to provide the verified models. 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, *the asset owner (Generator Owner or Transmission Owner)* shall provide a verified positive sequence dynamic model(s), with associated	

parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Change made. Request to clarify that asset owners are responsible to provide verified models, with modification to wording in R4 (and assumed R5).	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC GWG: R4.1 and R5.1: software/firmware may be updated multiple times throughout the year. Clarify that it only needs to be verified when that upgrade affects performance R4.3 and R5.3: is covered by PRC-019 and should be removed	
Likes 0	
Dislikes 0	
Response	
See Footnote for changes in Requirement R7. Requirement R7 only applies when the firmware change “alters the equipment response characteristic.” It should be understood that the intent of MOD-026-2 is to provide <u>dynamic models</u> for limiter and protection settings. Meanwhile, PRC-019 and PRC-024 pertain to <u>coordination</u> of the relays. The deliverables of all of the Standards are independent. That is to say, a relay can be accurately modeled regardless of whether it is properly coordinated per PRC-019 or PRC-024.	

Even if a relay is properly coordinated, there will always be a system event of magnitude that forces the unit out of its operational capability and results in a unit trip from protection settings. This performance can only be captured if protection elements are modeled.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
For Requirement 4, Part 4.3 and Requirement 5, Part 5.3, AZPS does not agree that modeling limiters and protection systems for prime movers of generator/synchronous condensers should be required as PRC-019 already ensures that limiters and protection systems are coordinated to ensure they operate as intended and are adequate for the intended application. For this reason, creating additional models would create additional work with very little reliability benefit. For Requirements 4 & 5, AZPS also requests that the SDT clarify which devices are the responsibility of the GO and which devices are the responsibility of the TO. For example, it would seem that the inverter based resources are the responsibility of the GO, and devices such as FACTS and VSC HVDC are the responsibility of the TO. R4: Unclear which devices are the responsibility of the GO and which devices are the responsibility of the TO. IBRs – GO; FACTS & HVDC - TO; R5 IBRs – GO, HVDC – TO (need clarification that this is correct and suggesting the above)	
Likes 0	
Dislikes 0	
Response	
It should be understood that the intent of MOD-026-2 is to provide dynamic models for limiter and protection settings. Meanwhile, PRC-019 and PRC-024 pertain to coordination of the relays. The deliverables of all of the Standards are independent. That is to say, a relay can be accurately modeled regardless of whether it is properly coordinated per PRC-019 or PRC-024. Even if a relay is properly coordinated, there will always be a system event of magnitude that forces the unit out of its operational capability and results in a unit trip from protection settings. This performance can only be captured if protection elements are modeled. Yes, the owner of the asset is the responsible party.	
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 TP, but the TP would need to validate the model and provide changes back to the GO and TO.	
Likes 0	
Dislikes 0	
Response	
Since the GO owns the equipment, the GO must be the entity that validates the model. The TP cannot run tests on and validate a model of someone else's equipment. The TP can only check the model for reasonableness and usability.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Suggest the following actions: 1. Create a separate 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	

The SDT's perspective is that a single standard will be more concise, effective, and interpretable than creating a separate standard for IBRs.

No change. Software/firmware version numbers are relevant, so the GO/TO and TP can understand what product is being supplied by the OEM.

Protection models are a key component of units' large signal responses. The SDT has significantly reduced the list of elements in the recent revisions.

The requirements of one Standard (MOD-026) cannot rely on the output of another Standard.

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. Model data must match model structure that is currently implemented in the industry used grid simulators. BPA believes that industry would need time to update, modify, or create software in order to meet the intention of IBR modeling.

Likes 0	
Dislikes 0	
Response	

The SDT understands that the implementation timeline (5 years total for R6) provides sufficient latency for positive sequence platforms to incorporate the necessary changes by the time that these models will need to be submitted.

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Change made. See footnote for large signal disturbance in R6. See Technical Rationale describing large signal disturbance.

It should be understood that the intent of MOD-026-2 is to provide dynamic models for limiter and protection settings. Meanwhile, PRC-019 and PRC-024 pertain to coordination of the relays. The deliverables of all of the Standards are independent. That is to say, a relay can be accurately modeled regardless of whether it is properly coordinated per PRC-019 or PRC-024.

Even if a relay is properly coordinated, there will always be a system event of magnitude that forces the unit out of its operational capability and results in a unit trip from protection settings. This performance can only be captured if protection elements are modeled.

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	No
Document Name	

Comment

The SDT did not address the structural concerns identified by the MRO NSRF Draft 1.

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.

Requirement R4 4.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating dynamic behavior of control systems.

R5 5.3: Same as comments for R2 2.3.

Likes 0	
Dislikes 0	

Response

Change made. Large signal disturbance description was added as a footnote in Requirement R6.

It should be understood that the intent of MOD-026-2 is to provide dynamic models for limiter and protection settings. Meanwhile, PRC-019 and PRC-024 pertain to coordination of the relays. The deliverables of all of the Standards are independent. That is to say, a relay can be accurately modeled regardless of whether it is properly coordinated per PRC-019 or PRC-024.

Even if a relay is properly coordinated, there will always be a system event of magnitude that forces the unit out of its operational capability and results in a unit trip from protection settings. This performance can only be captured if protection elements are modeled.

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

Answer	No
Document Name	

Comment

WEC Energy Group supports the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

See MRO NSRF response.

Casey Perry - PNM Resources - 1,3 - WECC

Answer	No
Document Name	

Comment

R4 and R5 sub requirements only mention IBR and not the other applicable generation facilities listed in the main requirements.

Likes 0	
Dislikes 0	

Response
Per footnote 6, IBR unit includes the inverter, converter, wind turbine generator, or HVDC converter.

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

Comment

The SDT did not address the structural concerns identified by the MRO NSRF Draft 1.

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.

Requirement R4 4.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating dynamic behavior of control systems.

R5 5.3: Same as comments for R2 2.3.

Likes 0	
Dislikes 0	

Response

Change made. See footnote for large signal disturbance in R6. See Technical Rationale describing large signal disturbance.

It should be understood that the intent of MOD-026-2 is to provide dynamic models for limiter and protection settings. Meanwhile, PRC-019 and PRC-024 pertain to coordination of the relays. The deliverables of all of the Standards are independent. That is to say, a relay can be accurately modeled regardless of whether it is properly coordinated per PRC-019 or PRC-024.

Even if a relay is properly coordinated, there will always be a system event of magnitude that forces the unit out of its operational capability and results in a unit trip from protection settings. This performance can only be captured if protection elements are modeled.

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

Manitoba Hydro does not agree with including a minimum modeling requirement. We think that it is up to the TP/PC to determine the required minimum modeling requirements and level of the modeling details as stated in R1 (1.1). If the TP/PC 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).

Likes 0	
Dislikes 0	

Response

No change. The basic model information must be outlined in R4/R5. This is similar to current MOD-026/027-1.

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE

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

The model(s) included in R4.2/5.2 shall "represent the in-service equipment". For example, if the Facility does not have auxiliary reactive resources, then they would not need to be included in the model.

Similarly for R4.3/5.3 model(s) need to represent enabled protections and limiting functions of the in-service equipment.

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

Answer	Yes
Document Name	

Comment

AECI supports comments provided by the NAGF.

Likes 0	
Dislikes 0	

Response

See NAGF response.

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

Answer	Yes
Document Name	

Comment

ITC supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
See EEI 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 submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E supports the modification to Requirements R4 and R5.	
Likes 0	

Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon concurs with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	

Answer	Yes
Document Name	
Comment	
The NAGF supports the proposed Requirements R4 and R5 modifications.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Kristine Howie - Kristine Howie Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
Answer	Yes
Document Name	
Comment	

Constellation has no additional comments. Kristine Howie behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy supports the proposed language in R4 and R5.	
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	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	

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

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
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	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 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 RSC	
Answer	
Document Name	
Comment	

Recommend the following language modification to clarify that asset owners (not interconnecting TOs) are responsible to provide the verified models.

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, *the asset owner (Generator Owner or Transmission Owner)* shall provide a verified positive sequence dynamic model(s), with associated parameters, and accompanying information that represents the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1.

Likes 0	
Dislikes 0	

Response

Change made. R2-R6 updated to say "asset owner", if applicable.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE continues to request the drafting team define 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.

Likes 0	
Dislikes 0	

Response

Josh Combs - Black Hills Corporation - 3

Answer	
Document Name	

Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	

Response
Sheila Suurmeier - Black Hills Corporation - 5

Answer	
Document Name	

Comment
BHC will not comment on this requirement.

Likes 0	
Dislikes 0	

Response
Lindsey Mannion - ReliabilityFirst - 10

Answer	
Document Name	

Comment
RF recommends minimum dynamics modeling requirements (including any necessary minimum modeling requirements for enabled protections and limiters) be specified in MOD-032 Attachment 1. The TP or PC can request other necessary modeling information as needed, but it is useful for Registered Entities and Compliance Enforcement Authorities if MOD-032 Attachment 1 provides a one-stop shop for the ERO-wide minimum modeling requirements.

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.***

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	

Comment

We would like clarification on the term "the structure of IBR unit model(s)…" and provide an example of an IBR unit model "structure."

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

No change. SDT believes this is mentioned in Footnote 11, that all inverter control modes, control blocks, and protections are represented in the model.

There is no requirement to model the complete system. One approach is to model the plant connected to a voltage source and play in the disturbance. Another is model the grid as an equivalent with a voltage behind an impedance. However, complex interactions may require modeling a portion of the system.

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) identified in Section 4.2.3, FACTS devices identified in Section 4.2.4.2, LCC HVDC identified in Section 4.2.5.1, and VSC HVDC identified in 4.2.5.2 to the BPS and to upon request of any of these applicable in-service devices by the TP/PC.
EMT models are complex and it will take long time to train personnel and develop EMT models.

In R6.2, it is not clear what is expected from large signal disturbance responses. It is only defined in the "Technical Rationale" document and more over it is not a NERC defined term in the NERC Glossary of Terms. SDT should consider defining what is meant by a large system disturbance within the standard.

For R6.2, the GO/TO has to provide device test results, which could be hardware in the loop (HIL) tests that are compared against EMT model simulation results. It is unclear whether a detailed network model must be used or a single machine infinite bus model. If the initial HIL tests were closely coordinated with the TP/PC (i.e., via FAC-002), there could be an acceptable network model that was used to confirm performance of models.

"FACTS devices per Section 4.2.4.2" should be changed to "FACTS devices identified in Section 4.2.4.2" to be consistent with the other language used in R6.

Likes 0	
Dislikes 0	

Response

Having an on-demand requirement for verified EMT models could be problematic. By having the TP define a need at any given time in the future, would create an emergent requirement for the GO to obtain an EMT model for an operational plant. For example, if a TP would require a verified EMT model in 2025, for a Facility commissioned in 2020, then the GO/TO would be considered a newly applicable Facility and have approximately one year to provide a verified EMT model to its TP. Whereas, with this approach all verified EMT models will need to be provided, if the Facility is commissioned after a specified date, which is a more straight forward approach. Obtaining verified EMT models is easier to achieve around the time of initial commissioning. Contracts that are in place with the equipment manufacturer allow for the delivery of a verified EMT model. Once the OEM is no longer under contract and more time passes, it becomes more difficult to obtain the required information. As more time passes from commissioning date, the risk increases that an OEM may no longer support the existing equipment, OEM personnel familiar with the technology or installation may have left the company, or the OEM may no longer be in business.

Change made. Revised the Implementation Timelines to provide responsible entities sufficient time to implement the changes of the reliability standard and develop expertise as needed. A responsible entity will now have 60 months (5 years) total to comply with Requirement R2-R6.

Change made. Description of large signal disturbance was added as a footnote in Requirement R6.

For R6.2 there is no requirement for modeling of the system in EMT. The device tests are compared to the model's response, typically connected to an ideal voltage source behind an impedance.

Change made. Language updated in R6.

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

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, 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 the footnotes 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 0	
Dislikes 0	

Response

Change made. Revised the Implementation Timelines to provide responsible entities sufficient time to implement the changes of the reliability standard and develop expertise as needed. A responsible entity will now have 60 months (5 years) total to comply with Requirement R2-R6.

Note there is no requirements for TP to perform studies with the EMT models.

No change. The SDT believes that attestations from the OEM for the respective equipment is the most cost effective way to ensure the structure of each model represents the supplied equipment. The SDT believes that having an attestation reduces the volume of parameter checking and validation by testing that would otherwise need to be completed by the GO/TO for each individual IBR unit, PPC, and auxiliary control devices. Therefore, this reduces the effort and cost for the GO/TO.

Change made. Description of large signal disturbance was added as a footnote in Requirement R6. The response to large signal disturbance referenced in R6.2 is limited to device tests such as type tests, control hardware in the loop tests, or other manufacturer test (see footnote 12). This is not a test performed on the device while connected to the transmission system, so there is no risk for causing a system disturbance. Additionally, there is an out if such device tests are not obtainable.

No change. Regarding OEL/UEL, EMT models are not required for synchronous generators in R6.

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No change. The monitoring required would be limited to Facility level voltage and currents. The need for monitoring equipment has been highlighted in the NERC Reliability Guideline: BPS-Connected Inverter-Based Resource Performance and various NERC Major Event Analysis Reports. Additionally, IEEE 2800-2022 specifies required measurement data in Clause 11 which would be sufficient in the case of R6.4.

R6.4 is validation of the Facility EMT model response compared to the measured response from a staged test or system disturbance. For remaining comment, it unclear which portion of R6 that is being referenced. There is no requirement or implied expectation in R6 in that there must be an identical match between the Facility EMT model's response and the measured response.

Casey Perry - PNM Resources - 1,3 - WECC	
Answer	No
Document Name	
Comment	
The R6 sub requirements only mention IBR not the other applicable generating facilities listed in the main requirement. Also, recommend requirement R6 address the confidentially of the EMT models.	
Likes 0	
Dislikes 0	
Response	
No change. EMT models are not required for synchronous generators.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports both the MRO NSRF and EEI comments.	
Likes 0	
Dislikes 0	

Response	
See MRO NSRF and EEI responses.	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	

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, 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.

{C}· EMT models are complex and it will take 5-years to train personnel and develop EMT models.

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

{C}· 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.

{C}· Entities will need time to identify and purchase new software for EMT models.

{C}· An EMT simulation for something like a NERC Odessa event will require a lot of computer power.

{C}· 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.

{C}· Verifying EMT models in R6 and R6.1 – R6.4

{C}o For R6.1 and concerns that Original Equipment Manufacturers (OEMs) aren't NERC entities.

{C}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."

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

{C}o large signal disturbances which could damage equipment or cause a system disturbance for a mandatory test.

{C}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:

{C}§ {C}Over Excitation Limiters and protection trips

{C}§ {C}Under Excitation Limiters and protection trips

{C}§ {C}Other protective models

{C}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.

{C}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 the footnotes 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 0	
Dislikes 0	

Response

See MRO NSRF and EEI responses.

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	No
Document Name	

Comment

To ensure consistent EMT models are provided and the specific EMT simulation tools are used, IID Planners will required time to be trainned on EMT models and its tools/software. Utilities unfamiliarity on EMT modeling will take time to correct

Likes 0	
Dislikes 0	

Response

Change made. Responsible entity will now have 60 months (5 years) to comply with Requirement R2-R6 with the Revised the Implementation Timelines.

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

Answer	No
Document Name	

Comment

FirstEnergy supports EEI's Comments which state:

Comments: EEI suggests the following changes in boldface to Requirement R6, noting that the information in the footnotes should be moved out of the footnotes into the body of the Reliability Standard. Additionally, attestations are unenforceable OEMs because they are non-registered entities. A better solution would be to include model requirement in OEM contracts moving forward.

R6. For applicable units of inverter based resources (IBRs) per identified in Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per identified in Section 4.2.5.1, and VSC HVDC per identified in 4.2.5.2, **commissioned after the date identified in Attachment 1, Row 11, the responsible** Generator Owner or Transmission Owner shall provide **an OEM** verified EMT model(s), **that includes all OEM supplied** 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)model(s) and accompanying information shall include at a minimum the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

6.1. **Model(s) that contain inverter control modes, control blocks, and protections represented, as applicable and be representative and accurate of the equipment installed at the generation resource.**;

6.2. Device test 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;

6.2.1 A device test that is hardware specific may include a factory type test, hardware in the loop test, or other manufacture manufacturer test to ensure the EMT model's large signal disturbance response emulates the supplied equipment to the extent possible, noting that even detailed EMT models of IBR plants, invariably have certain necessary approximations and limitations.

6.3. **OEM supplied EMT facility** model and with 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 **that conforms to the following**;

6.3.1 Models are to have the protections and controls that act on voltage, frequency, and/or current, or act on quantities derived from voltage, frequency, and/or current, which directly trip the IBR unit(s) or plant, or limit active/reactive output of the IBR unit or plant represented in the supplied EMT facility model. (*Examples of protections that should be included are IBR unit DC reverse current, DC bus over- and under-voltage, DC voltage unbalance, DC overcurrent, AC over- and under-voltage protection (instantaneous and RMS), AC overcurrent, over- and under-frequency protection, feeder (equivalent) AC over- and under-voltage, feeder (equivalent) over- and under-frequency, PLL (or equivalent) loss of synchronism, and phase jump tripping*.)

6.3.2 Model shall be non-proprietary to ensure compatibility with a wide range of modeling software.

6.4. Validation of the Facility EMT model response using the recorded response for a dynamic volt or VAR reactive power or voltage event, and for a dynamic active power or frequency event in which the power plant controller's or other Facility active power controller's perceived frequency deviates per Attachment 1, Note 1, resulting from either a staged test or a system disturbance; and

6.4.1 Exclusion: LCC HVDC facilities are excluded from the dynamic voltage or VAR event portion of the requirement.

6.5. Documentation 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.

Likes 0	
Dislikes 0	

Response

No change. Attachment 1, Row 13 will have a specific cutoff date for the exemption of R6.

No change. The SDT believes that attestations from the OEM for the respective equipment is the most cost effective way to ensure the structure of each model represents the supplied equipment. The SDT believes that having an attestation reduces the volume of parameter checking and validation by testing that would otherwise need to be completed by the GO/TO for each individual IBR unit, PPC, and auxiliary control devices. Therefore, this reduces the effort and cost for the GO/TO. Additionally, the proposed change by EEI "**shall provide an OEM verified EMT model(s)**" in R6 implies the OEM would verify the EMT model for the whole Facility.

For 6.3, the proposed language "**OEM supplied EMT facility"** implies that a single OEM would provide the Facility EMT model. Typically, a developer or integrator would combine the various EMT models provided by the respective equipment manufacturers.

Change made. Footnote describing "device test" remains. Language for "enabled protections and controls" combined in requirement language, while examples of protections are still in footnote.

No change. For 6.3.2., EMT models are specific to the OEM technologies and are proprietary to them. Even though the EMT model may be proprietary, the model can still be compatible with various modeling software. Model software compatibility is defined by the TP in Requirement R1.

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Change made for LCC HVDC revision.

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

Answer	No

Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
See MRO NSRF response.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
The EMT model response validation requirement to compare model response to measured system response described R6 part 6.4 likely requires the use of a TP/PC EMT model for the transmission system in the area around the IBR point of interconnection. If the TP/PC is not currently performing EMT modeling, such a model may not exist. Coordination with Project 2022-04 EMT Modeling may help develop improved EMT model verification requirements.	
Likes 0	
Dislikes 0	
Response	
No Change. The comparison in R6.4 does not require a system EMT model. It can be performed against an infinite voltage source behind an impedance representing the grid strength at the point of interconnection of the plant.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	
Model data must match model structure that is currently implemented in the industry used grid simulators. BPA believes that industry would need time to update, modify, or create software in order to meet the intention of IBR modeling.	
Likes 0	
Dislikes 0	
Response	
Change made. Responsible entity will now have 60 months (5 years) to comply with Requirement R2-R6 with the Revised the Implementation Timelines.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Transmission planners can't study the entire system with EMT models and these models 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 technical 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 precariously 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.

Likes 0	
Dislikes 0	

Response

No change. Having an on-demand requirement for verified EMT models could be problematic. By having the TP define a need at any given time in the future, would create an emergent requirement for the GO to obtain an EMT model for an operational plant. For example, if a TP would require a verified EMT model in 2025, for a Facility commissioned in 2020, then the GO/TO would be considered a newly applicable Facility and have approximately one year to provide a verified EMT model to its TP. Whereas, with this approach all verified EMT models will need to be provided, if the Facility is commissioned after a specified date, which is a more straight forward approach. Obtaining verified EMT models is easier to achieve around the time of initial commissioning. Contracts that are in place with the equipment manufacturer allow for the delivery of a verified EMT model.

Once the OEM is no longer under contract and more time passes, it becomes more difficult to obtain the required information. As more time passes from commissioning date, the risk increases that an OEM may no longer support the existing equipment, OEM personnel familiar with the technology or installation may have left the company, or the OEM may no longer be in business.

There is no requirement in this standard for system wide EMT studies.

See Technical Rationale for Requirement R6. EMT models are needed to understand the large signal disturbance response of an IBR Facility. NERC has published multiple disturbance reports, including the *Odessa Disturbance Report of May and June 2021 (page 22-31), and 2021 California Solar PV Disturbances of June and August 2021 (page 20-33)*. In both reports, NERC raised significant concerns regarding positive sequence modeling practices and the need for industry to verify and validate the accuracy of the models being used for reliability studies.

With EMT models provided under Requirement R6, a positive sequence stability models can be validated for IBR Facilities under Requirement R4/R5. The primary advantage of applying EMT simulations to validate positive sequence models is that simulations may be pushed to those operating boundaries and beyond whereas OEM unit tests would not do that. It is only in this pushing to boundaries that enables the TP to assess the ability of the positive sequence plant models to represent the large-disturbance behavior.

In the event a neighboring TP requests an EMT model, the model would be readily available rather than relying upon a string of requests from the neighboring TP to their respective GO/TO.

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	
No change. There is not a NERC approved list of EMT models. EMT models should be manufacturer specific (i.e., not generic).	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPCO signed on to ACES comments below: Requirement 6.1 requires the GO/TO to obtain an attestation from the OEM to verify the IBR model structure with respect to the supplied equipment. We have several concerns with this approach. Our concerns and subsequent recommendation are enumerated below: 1. The devices enumerated in R6.1 are often sourced from different vendors; therefore, it is highly likely that multiple attestations would be necessary to satisfy this requirement. Consider the following example for a hypothetical wind generation facility: a. Inverters are sourced from Vendor ABC. b. The power plant controller is either a PLC or DCS sourced from Vendor DEF.	

c. Wind turbine control PLC's (a.k.a. auxiliary control devices) are supplied by the wind turbine manufacturer Vendor GHI.
In this example of a hypothetical IBR facility, under the proposed Requirement 6.1, the GO would be required to obtain an attestation from 3 separate OEMs for 3 distinct types of equipment.
2. The OEM can only attest as to what was provided to the GO/TO and not to what is currently installed. The OEM has no way of knowing whether the supplied equipment was modified by third-party after it was provided to the GO/TO. In the example identified above, devices supplied by Vendors DEF and GHI are highly configurable and modifiable. Thus, it brings into question the relevancy of any attestation(s) provided by the OEM for those cases.
3. Depending on the modeling software used, the OEM may or may not have a working knowledge of the modeling software. It is possible that the OEM would lack the in-house expertise to provide an attestation to verify the structure of the model without additional external resources. This has the potential to further increase any associated costs.
4. For existing facilities commissioned after 1/1/2020 and prior to the compliance date for R6, requiring an attestation from the OEM that the model is accurate is overly burdensome to the GO/TO.
a. As the OEM is not a responsible entity, they are not subject to the requirements of this standard. Therefore, if an attestation was not provided at the time the equipment was procured, the GO/TO will likely need to pay the OEM to review the structure of the model and provide an attestation.
b. Requiring the GO/TO to obtain an attestation from an entity that has no requirement to provide said information places all the responsibility and none of the authority on the GO/TO vis-à-vis compliance with R6.1.

5. For new facilities built commissioned after the compliance date for R6, the GO/TO will need to contractually obligate the OEM(s) to provide the attestation(s) proposed in R6.1. This will likely increase the associated project costs.
It is our recommendation that R6.1 be modified so that the verification of the model structure is at the discretion of the GO/TO provided that the chosen method satisfies the Requirements identified in R1. It is our opinion that an engineering review by the

GO/TO would be an equally acceptable method for verifying the structure of the model. In short, we believe that an attestation from the OEM should be one acceptable method for verification, but not the only method.	
Likes 0	
Dislikes 0	
Response	
See ACES response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
AZPS does not agree that EMT modeling is necessary for dynamic model verification or that the 2 SARs have provided sufficient justification for why it is needed. 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. Additionally, as written, R1 applies to both synchronous and inverter based resources. Currently there are no EMT models available to synchronous generation as it has not been determined to be useful. For these reasons, EMT models should not be required for synchronous resources, and only required for inverter based resources on an as needed basis such as if the model response does not match the actual response from a system event. For Requirement 6, AZPS also requests that the SDT clarify which devices are the responsibility of the GO and which devices are the responsibility of the TO.	
Likes 0	
Dislikes 0	
Response	

Change made. R1.2 language was updated to be specific for EMT models identified in R6. Note there is no requirement for EMT models of synchronous generators.

See Technical Rationale for Requirement R6. EMT models are needed to understand the large signal disturbance response of an IBR Facility. NERC has published multiple disturbance reports, including the *Odessa Disturbance Report of May and June 2021 (page 22-31), and 2021 California Solar PV Disturbances of June and August 2021 (page 20-33)*. In both reports, NERC raised significant concerns regarding positive sequence modeling practices and the need for industry to verify and validate the accuracy of the models being used for reliability studies.

With EMT models provided under Requirement R6, a positive sequence stability models can be validated for IBR Facilities under Requirement R4/R5. The primary advantage of applying EMT simulations to validate positive sequence models is that simulations may be pushed to those operating boundaries and beyond whereas OEM unit tests would not do that. It is only in this pushing to boundaries that enables the TP to assess the ability of the positive sequence plant models to represent the large-disturbance behavior.
Having an on-demand requirement for verified EMT models could be problematic. By having the TP define a need at any given time in the future, would create an emergent requirement for the GO to obtain an EMT model for an operational plant. For example, if a TP would require a verified EMT model in 2025, for a Facility commissioned in 2020, then the GO/TO would be considered a newly applicable Facility and have approximately one year to provide a verified EMT model to its TP. Whereas, with this approach all verified EMT models will need to be provided, if the Facility is commissioned after a specified date, which is a more straight forward approach.

If the GO or TO owns any of the Facilities listed with Requirement R6, then they are responsible for providing the associated EMT models to the TP.

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	

Comment

On behalf of the SERC GWG:

R6 is quite burdensome. Suggest having the Planning Coordinator specify which units/plants/sites need to submit EMT models, rather than all

Likes 0	
Dislikes 0	

Response

No change. SDT proposes to do further education and outreach on this topic.

See Technical Rationale for Requirement R6. EMT models are needed to understand the large signal disturbance response of an IBR Facility. NERC has published multiple disturbance reports, including the Odessa Disturbance Report of May and June 2021 (page 22-31), and 2021 California Solar PV Disturbances of June and August 2021 (page 20-33). In both reports, NERC raised significant concerns regarding positive sequence modeling practices and the need for industry to verify and validate the accuracy of the models being used for reliability studies.
With EMT models provided under Requirement R6, a positive sequence stability models can be validated for IBR Facilities under Requirement R4/R5. The primary advantage of applying EMT simulations to validate positive sequence models is that simulations may be pushed to those operating boundaries and beyond whereas OEM unit tests would not do that. It is only in this pushing to boundaries that enables the TP to assess the ability of the positive sequence plant models to represent the large-disturbance behavior.

Having an on-demand requirement for verified EMT models could be problematic. By having the TP define a need at any given time in the future, would create an emergent requirement for the GO to obtain an EMT model for an operational plant. For example, if a TP would require a verified EMT model in 2025, for a Facility commissioned in 2020, then the GO/TO would be considered a newly applicable Facility and have approximately one year to provide a verified EMT model to its TP. Whereas, with this approach all verified EMT models will need to be provided, if the Facility is commissioned after a specified date, which is a more straight forward approach.

Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	No
Document Name	
Comment	
Buckeye Power, Inc supports the comments made by ACES Power Marketing.	
Likes 0	
Dislikes 0	
Response	
See ACES responses.	
Kristine Howie - Kristine Howie Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
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. Kristine Howie behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Change made. 5 years total provided for Implementation Plan. Additionally, see Implementation Plan section *Initial Performance of Periodic Requirements, "*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). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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."	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #5.	
Likes 0	
Dislikes 0	
Response	
See EEI responses.	

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. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Change made. 5 years total provided for Implementation Plan. Additionally, see Implementation Plan section *Initial Performance of Periodic Requirements, "*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). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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."	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
R6 asks for GO or TO to provide an EMTP model to **its** Transmission Planner. In the case of HVDC/VSC a second Transmission Planner might be connected to the other end of the HVDC/VSC and will also need to have access to this EMT model. Furthermore, this Transmission Planner might use a different EMT software requiring a different EMT model from the GO or TO. We believe a note should be added indicating this.	

-6.3 does not indicate what to do in the case an existing facility's manufacturer is out of business (for instance, in the case an EMTP model was not delivered at commissioning). A generic model (based on the technology used or site tuned) should be allowed for those cases.	
Likes 0	
Dislikes 0	
Response	
No change. This is one reason the PC is involved with developing joint modeling requirements and processes. This would be addressed by the acceptable EMT model defined in R1.2. Attachment 1, Row 13 (exemption for R6), provides the GO/TO an exemption to all of R6, if the OEM is no longer in business.	
Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC	
Answer	No
Document Name	
Comment	
R6 asks for GO or TO to provide an EMTP model to **its** Transmission Planner. In the case of HVDC/VSC a second Transmission Planner might be connected to the other end of the HVDC/VSC and will also need to have access to this EMT model. Furthermore, this Transmission Planner might use a different EMT software requiring a different EMT model from the GO or TO. We believe a note should be added indicating this. 6.3 does not indicate what to do in the case an existing facility's manufacturer is out of business (for instance, in the case an EMTP model was not delivered at commissioning). A generic model (based on the technology used or site tuned) should be allowed for those cases.	
Likes 0	
Dislikes 0	
Response	
See Hydro Quebec response.	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No

Document Name	
Comment	
CEHE supports the comments as submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon concurs with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	

Likes 0	
Dislikes 0	

Response

See EEI response.

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

See EEI 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

PGAE agrees with the comments and updates provided by EEI for Requirement R6 on the relocation of the footnotes and that attestations are unenforceable OEMs.

Likes 0	
Dislikes 0	

Response	
See EEI 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 submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
ITC supports the comments submitted by EEI ITC has the following additional comments: Similar to the current NERC acceptable models list for dynamics models, there needs to be developed an acceptable models list for EMT models. The provided data should not be OEM proprietary models but rather a standard model library. This should be developed prior to the requirement for models going into effect.	
Likes 0	
Dislikes 0	

Response
See EEI response. No change. EMT models should be OEM specific and not generic.

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

R6 should be reworded such that TPs can identify and then request an EMT model for facilities that are likely to pose risk. Validated EMT models should not be a requirement for all facilities in the proposed applicability scope. At-best, EMT model requests should be driven by specific, critical need as determined by Transmission Planners and then requested under MOD-032. NERC is proposing an EMT Task Force to better understand EMT models and provide guidance around their use. Should the EMT model requirement precede the development of guidance around model development?

Reasons for limiting the applicability:

- EMT modeling for every BES facility will create an undue burden and expense for GOs, TOs and TPs. With the large number of validations and/or revalidations with these requirements, 90 days may not be sufficient to address all usability assessment comments, additional data/model request, etc.
- R.6.1., R.6.2., GOs don’t have means to require either of these two items from vendors. For some of the older facilities models, or generic models created for facilities where vendor does not exist these tests are not available.
- EMT modeling software requires specialized computer hardware for analysis and is expensive.
- EMT software analysis requires a unique set of engineering skills and requires much training.
- There is no evidence from TPs that every facility has a need for an EMT model. R.6.4 the necessity of EMT model validation should be mutually agreed and discussed in detail with the corresponding TP, and not mandated by the standard.
- R.6.5. Model benchmarking will place an unnecessary burden on GOs, as positive sequence and EMT modeling is used for different purposes. The amount of details for EMT would depend upon the type of studies intended by TP.
- There is no way to stage a large signal disturbance system test. If one could be derived, it would likely be considered a BES reliability risk by the TP and RC and not allowed.   Factory type testing, while attempting to emulate the response of the equipment to large system disturbances, invariably have certain necessary approximations and limitations and are unlikely to sufficiently represent all types of disturbances which will occur on the system.   This fact is likely to put owners of IBR resources and TPs in a never ending re-model loop should the model fail to accurately predict the response of the equipment to a disturbance not previously considered.

- Not all facilities have recording equipment installed and configured to capture large signal disturbance events and the facility response. This means more equipment and manpower costs to purchase, install and maintain.

Likes 0	
Dislikes 0	

Response

Change made. Revised the Implementation Timelines to provide responsible entities sufficient time to implement the changes of the reliability standard and develop expertise as needed. A responsible entity will now have 60 months (5 years) to comply with Requirement R2-R6.

No change for other items.

Note the commissioning data cut-off of the facility in row 13 of attachment 1. If the OEM in no longer in business or no longer supports the models of the in-service equipment, there is an exemption for R6.

See Technical Rationale for Requirement R6. EMT models are needed to understand the large signal disturbance response of an IBR Facility. NERC has published multiple disturbance reports, including the Odessa Disturbance Report of May and June 2021 (page 22-31), and 2021 California Solar PV Disturbances of June and August 2021 (page 20-33). In both reports, NERC raised significant concerns regarding positive sequence modeling practices and the need for industry to verify and validate the accuracy of the models being used for reliability studies.

With EMT models provided under Requirement R6, a positive sequence stability models can be validated for IBR Facilities under Requirement R4/R5.

The primary advantage of applying EMT simulations to validate positive sequence models is that simulations may be pushed to those operating boundaries and beyond whereas OEM unit tests would not do that. It is only in this pushing to boundaries that enables the TP to assess the ability of the positive sequence plant models to represent the large-disturbance behavior.

Having an on-demand requirement for verified EMT models could be problematic. By having the TP define a need at any given time in the future, would create an emergent requirement for the GO to obtain an EMT model for an operational plant. For example, if a TP would require a verified EMT model in 2025, for a Facility commissioned in 2020, then the GO/TO would be considered a newly applicable Facility and have approximately one year to provide a verified EMT model to its TP. Whereas, with this approach all verified EMT models will need to be provided, if the Facility is commissioned after a specified date, which is a more straight forward approach.

Obtaining verified EMT models is easier to achieve around the time of initial commissioning. Contracts that are in place with the equipment manufacturer allow for the delivery of a verified EMT model. Once the OEM is no longer under contract and more time passes, it becomes more difficult to obtain the required information. As more time passes from commissioning date, the risk increases that an OEM may no longer support the existing equipment, OEM personnel familiar with the technology or installation may have left the company, or the OEM may no longer be in business.

In the event a neighboring TP requests an EMT model, the model would be readily available rather than relying upon a string of requests from the neighboring TP to their respective GO/TO.

There is not requirement for a large-disturbance system test. The response to large signal disturbance referenced in R6.2 is limited to device tests such as type tests, control hardware in the loop tests, or other manufacturer test (see footnote 12). This is not a test performed on the device while connected to the transmission system, so there is no risk for causing a system disturbance. Additionally, there is an exemption for R6.2, if such device tests are not obtainable. These tests are limited.

The monitoring required would be limited to plant level voltage and currents. The need for monitoring has been highlighted in the NERC Reliability Guideline: BPS-Connected Inverter-Based Resource Performance and various NERC Major Event Analysis Reports. Additionally, IEEE 2800-2022 specifies required measurement data in Clause 11 which would be sufficient in the case of R6.4.

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

Answer	No
Document Name	

Comment

Requirement 6.1 requires the GO/TO to obtain an attestation from the OEM to verify the IBR model structure with respect to the supplied equipment. We have several concerns with this approach. Our concerns and subsequent recommendation are enumerated below:

1. The devices enumerated in R6.1 are often sourced from different vendors; therefore, it is highly likely that multiple attestations would be necessary to satisfy this requirement. Consider the following example for a hypothetical wind generation facility:
a. Inverters are sourced from Vendor ABC.
b. The power plant controller is either a PLC or DCS sourced from Vendor DEF.
c. Wind turbine control PLC’s (a.k.a. auxiliary control devices) are supplied by the wind turbine manufacturer Vendor GHI.
In this example of a hypothetical IBR facility, under the proposed Requirement 6.1, the GO would be required to obtain an attestation from 3 separate OEMs for 3 distinct types of equipment.

2. The OEM can only attest as to what was provided to the GO/TO and not to what is currently installed. The OEM has no way of knowing whether the supplied equipment was modified by third-party after it was provided to the GO/TO. In the example identified above, devices supplied by

Vendors DEF and GHI are highly configurable and modifiable. Thus, it brings into question the relevancy of any attestation(s) provided by the OEM for those cases. 3. Depending on the modeling software used, the OEM may or may not have a working knowledge of the modeling software. It is possible that the OEM would lack the in-house expertise to provide an attestation to verify the structure of the model without additional external resources. This has the potential to further increase any associated costs. 4. For existing facilities commissioned after 1/1/2020 and prior to the compliance date for R6, requiring an attestation from the OEM that the model is accurate is overly burdensome to the GO/TO. a. As the OEM is not a responsible entity, they are not subject to the requirements of this standard. Therefore, if an attestation was not provided at the time the equipment was procured, the GO/TO will likely need to pay the OEM to review the structure of the model and provide an attestation. b. Requiring the GO/TO to obtain an attestation from an entity that has no requirement to provide said information places all the responsibility and none of the authority on the GO/TO vis-à-vis compliance with R6.1. 5. For new facilities built commissioned after the compliance date for R6, the GO/TO will need to contractually obligate the OEM(s) to provide the attestation(s) proposed in R6.1. This will likely increase the associated project costs. It is our recommendation that R6.1 be modified so that the verification of the model structure is at the creation of the GO/TO provided that the chosen method satisfies the Requirements identified in R1. It is our opinion that an engineering review by the GO/TO would be an equally acceptable method for verifying the structure of the model. In short, we believe that an attestation from the OEM should be acceptable method for verification, but not the method.

Likes 0	
Dislikes 0	

Response

The hypothetical example seems probable. No change. The SDT believes that attestations from the OEM for the respective equipment is the most cost effective way to ensure the structure of each model represents the supplied equipment. The SDT believes that having an attestation reduces the volume of parameter checking and validation by testing that would otherwise need to be completed by the GO/TO for each individual IBR unit, PPC, and auxiliary control devices. Therefore, this reduces the effort and cost for the GO/TO.

Correct. The attestation in R6.1 pertains to “the structure of IBR unit model(s), power plant controller model, and auxiliary control devices model(s) represent the equipment supplied by the OEM”. R6.1 and R6.2 are foundational to ensure the Facility EMT model of R6.3 is accurate. Any changes to the parameters should be reflected in the Facility EMT model of R6.3.

There is ongoing collaboration with OEM and EMT modelling software companies. The exemption date for R6 in Attachment 1 is to provide exemption for legacy Facilities where it out be problematic to obtain documentation or an attestation. If an attestation from an OEM is not obtainable, the GO or TO shall document the reason. The SDT agrees that this may increase the cost for newly commissioned Facilities. The SDT believes that attestations from the OEM for the respective equipment is the most cost effective way to ensure the structure of each model represents the supplied equipment. The SDT believes that having an attestation reduces the volume of parameter checking and validation by testing that would otherwise need to be completed by the GO/TO for each individual IBR unit, PPC, and auxiliary control devices.

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
EMT model requirement seems to be based on one event and not justified in the technical criteria how it would improve the issues identified in the Odessa Report and the WECC reports. This would not constitute an issue that is continent wide. Maybe a region-specific requirement as the issue seems to be in the WECC region. Also, the models that are available for EMT do not seem to add any more value compared to the positive sequence models.	
Likes 0	
Dislikes 0	
Response	
See Technical Rationale for Requirement R6. EMT models are needed to understand the large signal disturbance response of an IBR Facility. NERC has published multiple disturbance reports, including the *Odessa Disturbance Report of May and June 2021 (page 22-31), and 2021 California Solar PV Disturbances of June and August 2021 (page 20-33)*. In both reports, NERC raised significant concerns regarding positive sequence modeling practices and the need for industry to verify and validate the accuracy of the models being used for reliability studies. With EMT models provided under Requirement R6, a positive sequence stability models can be validated for IBR Facilities under Requirement R4/R5. The primary advantage of applying EMT simulations to validate positive sequence models is that simulations may be pushed to those operating	

boundaries and beyond whereas OEM unit tests would not do that. It is only in this pushing to boundaries that enables the TP to assess the ability of the positive sequence plant models to represent the large-disturbance behavior.

Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The SDT should differentiate between sites commissioned before 2020 and have not been updated versus newly commissioned wind farms and windfarms that have been upgraded since 2020.

Likes 0	
Dislikes 0	

Response

No change. If the Facility has a commissioning date after the R6 exemption date in Attachment 1, then it would be subject to Requirement R6.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NVE 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, 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]

NVE has concerns about the implementation of required EMT models. While NVE 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

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

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."

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.

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

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.

It's NVE'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.

NVE believes 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 the footnotes 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 0	
Dislikes 0	

Response

See MRO NSRF responses.

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports NPCC Regional Standards Committee's comments.

Likes 0	
Dislikes 0	

Response

See NPCC response.

Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Same as No. 2 above	
Likes 0	
Dislikes 0	
Response	
See Question 2 response.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Same comments as in question 2 above.	
Likes 0	
Dislikes 0	
Response	
See Question 2 response.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	

The NAGF supports the proposed Requirement R6 modifications.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.

Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
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	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
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	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
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	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
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	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	
Document Name	
Comment	

BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends Footnote 13 be consistent with the description of Facility in section A 4.2.	
Likes 0	
Dislikes 0	
Response	
Change made. Updated R6.3 language (previously Footnote 13. Changed from plant to Facility.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
-R6 asks for GO or TO to provide an EMTP model to **its** Transmission Planner. In the case of HVDC/VSC a second Transmission Planner might be connected to the other end of the HVDC/VSC and will also need to have access to this EMT model. Furthermore, this Transmission Planner might use a different EMT software requiring a different EMT model from the GO or TO. We believe a note should be added indicating this.	

-6.3 does not indicate what to do in the case an existing facility's manufacturer is out of business (for instance, in the case an EMTP model was not delivered at commissioning). A generic model (based on the technology used or site tuned) should be allowed for those cases.	
Likes 0	
Dislikes 0	
Response	
No change. This is one reason the PC is involved with developing joint modeling requirements and processes. This would be addressed by the acceptable EMT model defined in R1.2. Attachment 1, Row 13 (exemption for R6), provides the GO/TO an exemption to all of R6, if the OEM is no longer in business.	

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*.**

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NVE recommends that NERC MOD-026-1 Requirement R4, Footnote 5 be added back into the Standard as provided clarification to the phrase 'alter equipment response characteristics'.

NVE has concerns with the "large" signal disturbances. NVE 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 0	
Dislikes 0	
Response	

As for the comment on footnote, change made. The SDT addresses the commenter's concern by adding a new footnote to add clarify over what is "the change that alters the equipment response characteristic".

As for large disturbance comment, please refer to SDT's response to comments on Question 4. Footnote was added to R6.

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	

The timeframes are not aligned between R8 and M8. R8 states 120 calendar days while M8 states 90 calendar days. As this was a change from the previous draft, it is assumed that M8 was simply overlooked. R9 references MOD-026-2 Attachment 1; however, there is no corresponding section in Attachment 1. We recommend one of the following actions:
1. Remove the reference to Attachment 1 from R9.
2. A section specific to the notification of denial timeline be added to the periodicity table in Attachment 1
OR
3. Add additional clarification to R9 indicating how the periodicity table in Attachment 1 is applicable to R9.

Given that R9 already contains a timeline of 90 calendar days within the Requirement, our preferred course of action is item 1 above.

Likes 0	
Dislikes 0	

Response

Change made.

The SDT recognizes your concern that the timeframe information in R8, M8 and R9 is either inconsistent or duplicative (e.g. mismatch between R8 and M8; R9 timeline not referenced in attachment 1).

To address this concern, the inconsistency in timeframe information has been reconciled by moving timeframe information in R7, R8, R9 to Attachment 1 (Row 7 and Row 8).

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee

Answer	No
Document Name	

Comment

In R7, updated models may be provided after making a hardware, software, firmware, control mode, or setting changes, this should be changed to 90 days prior to making the changes so that they may be evaluated prior to the facility being returned to service.

MOD-026-2 R8, says TP shall provide the written response within 120 days. While in M8, it says TP must provide dated evidence with 90 days. Is this a kind of conflict? M8 should have been changed. Should R9 also be 120 days?	
Likes 0	
Dislikes 0	
Response	
No change. The SDT understands that the TP has a business need to capture and evaluate the model change information prior to GO/TO making certain changes to the facility. However, the purpose of MOD-026-2 R7 is to ensure that the validated model is provided to TP for updating the planning database “after the fact”. We believe that FAC-002 is a better venue to address the model need mentioned in the comment. Once the facility change is determined to be a qualified change (or material modification in FAC-002-3), the TP could use FAC-002 rather than MOD-026 to request model change information. Change made to R8/M8. To avoid inconsistency and duplication, all time frame information in R8/M8 is moved to Attachment 1.	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
R8 is a purely administrative requirement for the TP. The requirement should be focused on any technical comments from the TP or PC being responded to by the GO or TO. This appears to be the intent of R9. **Regarding R9:** The GO or TO providing “technical justification and supporting evidence for maintaining the current model” may be an unacceptable response to deficiencies identified the TP or PC. This would imply the right of the GO or TO to by-pass TP or PC requirements and diminish the ability of the TP and PC to perform needed studies with a potentially deficient model. It recommended to either strike this portion of the requirement, or provide a mechanism for dispute resolution.	
Likes 0	
Dislikes 0	
Response	

No change. R8 allows the TP to review the materials submitted.

Change made on R9.

The SDT understand your concern that the "technical justification and supporting evidence for maintaining the current model" has a potential to be used by GO or TO to bypass TP or PC requirements. The 3rd bullet item in R9 is changed to:

- "A resubmission of the current model and accompanying information in accordance with Requirements R2, R3, R4, R5, or R6, with additional technical justification and supporting evidence to address the notification of denial or model review from the Transmission Planner.."

The new wording will direct the process back to R8 (a requirement for TP to respond to verified model submissions) and keep the conversation between TP and GO going until a resolution is reached.

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	

Requirement R7 is a little ambiguous in how it is worded. It could be changed to be similar to R9. Recommend changing the wording of R7 to:

Each Generator Owner or Transmission Owner upon making a hardware, software, firmware, control mode, or setting change to in-service equipment specified in Part 2.2, 2.3, 3.2, 3.3, 4.2, 4.3, 5.2, 5.3, or 6.3 that alters the equipment response characteristic, in accordance with MOD-026-2 Attachment 1 shall, within 180 days, provide to its Transmission Planner:

• An updated verified model and accompanying information in accordance with Requirements R2–R6, or

• A plan to verify the model in accordance with Requirements R2–R6.

Likes 0	
Dislikes 0	

Response

Change made. R7 has been revised as suggested to add clarity and readability.

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

Answer	No
Document Name	

Comment

Southern Company recommends replacement of “Transmission Planner” with “Transmission Planner and/or Planning Coordinator” in Requirements R7., R8., and R9.

We have 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.

The model verification periodicity information contained in Requirement R7 should be removed in favor of the information already provided in Attachment 1. Duplicative periodicity information in this requirement adds unnecessary confusion for entities with obligations.

Likes 0	

Dislikes 0	
Response	
Replace TP with TP/PC - No change. It is the intention of MOD-026-2 to place the R7, R8, R9 responsibility on TP's shoulder. As described in Requirement R1, "Each Transmission Planner and its Planning Coordinator shall jointly develop dynamic model verification requirements and processes." However, the PC does not need to be explicitly mentioned in each of the requirement subparts. For example, the TP will use the acceptance criteria developed in Requirement R1.3, to review and accept the submitted information as part of Requirement R8, which does not involve the PC. Defining large disturbance - See Question 5 response. Inconsistent timeframe information - Change made. To avoid inconsistency and duplication, all time frame information in R7, R8/M8, R9 is moved to Attachment 1.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
ITC supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
See EEI 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 submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
See EEI 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	
PGAE agrees with the comments provided by EEI for: 1 - Question 6 on the model verification periodicity information contained in Requirements R7, R8, and R9 should be removed in favor of the information provided in Attachment 1. The duplicative periodicity information in the Requirement and Attachment adds unnecessary confusion to an entity's obligations. 2 - The input on Footnote 5 from MOD-026-1 Requirement R4 on reconsideration of the deletion or adding similar clarifying language to the next draft. 3 – The input on Requirement R9 needs to include a dispute resolution process.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	

Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	

Exelon concurs with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE supports the comments as submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC	
Answer	No
Document Name	
Comment	
At M8, the delay should be 120 calendar days, to be consistent with R8.	
Likes 0	
Dislikes 0	

Response	
Change made. To avoid inconsistency and duplication, all time frame information in R7, R8/M8, R9 is moved to Attachment 1.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Recommend that the term, "control mode," in R7 should be changed to, "type of control," as was done in R3.1. Combined cycle units frequently shift between the load setpoint control mode and firing temperature limit control mode, for example, and fossil units at very high output go from throttling to the valves-wide-open mode. These transitions do in fact alter the response to frequency disturbances, but it would be impossible to reverify models for each episode. MOD-026-2 R7 should apply only when converting a fossil unit from the mechanical hydraulic to electo-hydraulic governors or making a similar change in control type.	
Likes 0	
Dislikes 0	
Response	
No change to the term "control mode". Alternatively, the SDT addresses the commenter's concern by adding a new footnote to add clarify over what is "the change that alters the equipment response characteristic". Please find the last sentence in the new footnote (see below) that exempts the type of control mode change described by the commenter. Added to Footnote "Automatic change of control mode or a control setting that is implemented in the plant control systems do not apply to Requirement R7."	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

In MOD-026-2 R8, it says TP shall provide the written response within 120 days. While in M8, it says TP must provide dated evidence with 90 days. Is this a typo error?	
Response	
Change made. Yes, this is a typo. To avoid inconsistency and duplication, all time frame information in R7,R8/M8, R9 is moved to Attachment 1.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #6.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	No
Document Name	
Comment	
Buckeye Power, Inc supports the comments made by ACES Power Marketing.	
Likes 0	
Dislikes 0	

Response	
See ACES response.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC GWG: R7 is a little ambiguous in how it is worded. It could be changed similar to R9: Each Generator Owner or Transmission Owner upon making a hardware, software, firmware, control mode, or setting change to in-service equipment specified in Part 2.2, 2.3, 3.2, 3.3, 4.2, 4.3, 5.2, 5.3, or 6.3 that alters the equipment response characteristic, in accordance with MOD-026-2 Attachment 1 shall, within 180 days, provide to its Transmission Planner: • An updated verified model and accompanying information in accordance with Requirements R2–R6, or • A plan to verify the model in accordance with Requirements R2–R6.	
Likes 0	
Dislikes 0	
Response	
Change made. R7 has been revised as suggested to add clarity and readbility.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports NAGF comments.	

Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	

For Requirement 7, AZPS recommends that the following bolded edit be added:

R7. Each Generator Owner or Transmission Owner shall provide an updated verified model(s), or a plan to verify the model(s), in accordance with one or more of Requirements R1, R3, R4, R5, of R6 to its Transmission Planner within 180 calendar days of making a **functional change** to hardware, software, firmware, control mode, or setting change to in-service equipment specified in Part 2.2, 2.3, 3.2, 3.3, 4.2, 4.3, 5.2, 5.3, or 6.3 that **results in a different response of the unit or would impact an interconnected transmission line** alters the equipment response characteristic, in accordance with MOD-026 Attachment 1.

For Requirements 7 and 9, AZPS does not agree with removing the phase “mutually agreed upon” as we believe any that the GO and the TO should agree on plans for model verification.

Likes 0	
Dislikes 0	
Response	

No change.

Instead of qualifying the change with adjective “Functional”, the SDT address the commenter’s concern in a more descriptive way. Footnote 15: a new footnote added to clarify what is the in-scope change. Please find details in draft 3.

The edit is not accepted, because GO/TO often do not have capability to determine what change would **impact the interconnected transmission line** (supposed to be a TP's duty**)**. Beside, the qualifier "**results in a different response of the unit"** is somewhat duplicative of the qualifier "that alters the equipment response characteristic".

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPCO signed on to ACES comments below: The timeframes are not aligned between R8 and M8. R8 states 120 calendar days while M8 states 90 calendar days. As this was a change from the previous draft, it is assumed that M8 was simply overlooked. R9 references MOD-026-2 Attachment 1; however, there is no corresponding section in Attachment 1. We recommend one of the following actions: 1. Remove the reference to Attachment 1 from R9. 2. A section specific to the notification of denial timeline be added to the periodicity table in Attachment 1 OR 3. Add additional clarification to R9 indicating how the periodicity table in Attachment 1 is applicable to R9. Given that R9 already contains a timeline of 90 calendar days within the Requirement, our preferred course of action is item 1 above.	
Likes 0	
Dislikes 0	
Response	
Change made. To avoid inconsistency and duplication, all time frame information in R7,R8/M8, R9 is moved to Attachment 1.	
Josh Combs - Black Hills Corporation - 3	
Answer	No

Document Name	
Comment	
BHC supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
BHC supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHC supports the NAGF comments.	

Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
BHC supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
The 90-day timeline in Requirement R8 has been revised to 120 calendar days. However, the corresponding Measure M8 has not been revised accordingly. Please correct this apparent oversight. The rationale for increasing the TP timeline in R8 was reported as the additional scope of reviewing the EMT models. The same rationale would also apply to the GO/TO that need to accommodate the additional scope of developing these EMT models and/or the associated verification plans. For ency, BC Hydro supports increasing the R9 timeline for the GO/TO in R9 from 90 to 120 days, consistent with the revised R8 timeline for the TP.	

Likes 0	
Dislikes 0	

Response

Change made. To avoid inconsistency and duplication, all time frame information in R7, R8/M8, R9 is moved to Attachment 1. To accommodate the added scope of EMT modeling, the SDT addresses the commenter's concern by increasing the R9 deadline from 90 days to 120 days.

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

Answer	No
Document Name	

Comment

1 R1 is open ended - Specifics to comply should be detailed in this standard as in the existing MOD-026 and MOD-027 standards.

2. M8 - Remove the need to supply review date of submitted model and accompanying information. Response within the 90 days is sufficient.

3. R7 - 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.

4. M8 - Revision error: Change 90 calendar days to revised 120 calendar days.

Likes 0	
Dislikes 0	

Response

Increasing R8 deadline to 120 days is to account for the TP's added scope of reviewing EMT model submission. similar extension is given to R9 (increasing from the GO/TO's response time to 120 days)

Refer to attachment 1 row 6.

Change made. To avoid inconsistency and duplication, all time frame information in R7,R8/M8, R9 is moved to Attachment 1.

Lindsey Mannion - ReliabilityFirst - 10

Answer	No
Document Name	
Comment	
RF recommends adding a statement to the "Technical justification and supporting evidence for maintaining the current model" option in R9 stipulating that the technical justification cannot be used to justify retaining a model, format, or level of detail that is not acceptable to the TP/PC. As currently written, GO/TOs may attempt to use the R9 "technical justification" option to maintain models that are not acceptable to the TP/PC under R1 Part 1.1 or Part 1.2.	
Likes 0	
Dislikes 0	
Response	
Change made. The SDT understands the concern that the 3rd bullet item in R9 could be potentially used by GO or TO to by-pass TP or PC requirements. The 3rd bullet item in R9 is therefore changed to: "A resubmission of the current model and accompanying information in accordance with Requirements R2, R3, R4, R5, or R6, with additional technical justification and supporting evidence to address the notification of denial or model review from the Transmission Planner."	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
We recommend adding that the Transmission Planner's request for a model review in R9 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 R3, R5 footnote 6 and MOD-027 R3. Also, please note that the language shown 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." R9 in draft standard: "R9. Each Generator Owner or Transmission Owner receiving a notification of denial under Requirement R8 or a *request from its Transmission Planner for a model review due to identified model or accompanying information deficiencies* shall provide a written response to its Transmission	

Planner within 90 calendar days of receiving a notification or request, *in accordance with the periodicity in MOD-026-2 Attachment 1*. The written response shall contain one of the following:”

R9 on page 6 of Mapping Document:
“R9. Each Generator Owner or Transmission Owner receiving a notification of denial under Requirement R8 or a *technical justification for model review* shall provide a written response to its Transmission Planner within 90 calendar days of receiving a notification. The written response shall contain one of the following:”

Likes 0	
Dislikes 0	

Response

No change.

The SDT believes there are many other reasons that the TP may use justify a model review (such as model data is found in conflict with other technical records, test reports or operating orders). It would be unduly restrictive for TP if the model review can only be justified on the basis of the simulated unit or plant response not matching the measured unit or plant response to an event.

The SDT believes that “a request from its Transmission Planner for a model review due to identified model or accompanying information deficiencies” is a better fit for the intended purpose of requirement R9, because it is broader than the old term “technically justified” defined in MOD-026-1.

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

Answer	No
Document Name	

Comment

Minnesota Power agrees with MRO’s NERC Standards Review Forum’s (NSRF) comments.

Likes 0	
Dislikes 0	

Response

See MRO response.

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

Answer	No
Document Name	

Comment

FirstEnergy supports EEI's Comments which state:

The model verification periodicity information contained in Requirements R7, R8 and R9 should be removed in favor of the information provided in Attachment 1. Duplicative periodicity information in these requirement adds unnecessary confusion as to entity obligations. For example:

Requirement R7 states updated verified model(s) or a plan to verify the model per R2, R3, R4, R5 or R6 is to be submitted to the TP within 180 calendar days, while Attachment 1, Row 5 states 180 days is required unless a plan is submitted, then 365 days after submission of a plan is allowed. To avoid this conflict, all model verification periodicity should only be in attachment 1.

Deletion of Footnote 5, MOD-026-1, Requirement 4 (*R4 has been mapped to R7*): EEI is concerned that the deletion of footnote #5 from the MOD-026-1 (i.e., not included in the current draft) has created an area of possible compliance ambiguity and risk for responsible entities. This footnote was previously included in MOD-026-1, R4 to provide clarity over what kind of changes “that alter the equipment response characteristics” are in scope. Moreover, the deletion of this footnote leaves auditors and responsible without clear direction as to the intended scope. For this reason, we ask the SDT to reconsider the deletion of footnote 5 (from MOD-026-1) or to add similarly clarifying language to the next draft.

EEI additionally Requirement R9 needs to include a dispute resolution process in order to resolve agreements between the TP and GOs and TOs on the acceptability of the models provided.

Likes 0	
Dislikes 0	

Response

Inconsistent and duplicative time frame information - Change made. To avoid inconsistency and duplication, all time frame information in the new draft has been moved from R7,R8/M8, R9 to Attachment 1.

Deletion of Footnote 5, MOD-026-1, Requirement 4 - Change made. Draft 2, as currently written, has already included the following qualifiers to define the in-scope changes:

a. Changes on in-service equipment specified in Part 2.2, 2.3, 3.2, 3.3, 4.2, 4.3, 5.2, 5.3, or 6.3
b. Hardware, software, firmware, control mode, or setting change

In addition, the SDT adopts EEI's suggestion and add a new footnote (see below) to R7 to provide additional clarify over what kind of changes "that alter the equipment response characteristics" are in scope for R7.

New Footnote 15: "Such changes include: (a) exciter, voltage regulator, plant volt/var, power system stabilizer, or governor control replacement including software alterations; (b) addition or replacement of protection systems that deploy under- and over- voltage and/or under- and over-frequency elements; (c) plant digital control system addition or replacement; (d) plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, or other equipment); (e) software, firmware or setting change in the equipment (such as exciter, voltage regulator, power system stabilizer, excitation limiter, governor, plant controller, FACTs devices or IBR unit, or other equipment.) that alters its dynamic response characteristics; (f) a permanent change in the voltage or frequency control mode (such as manually switching the voltage regulator from power factor control to automatic voltage control); or (g) any other equipment change that alters its dynamic response characteristic. Automatic change of control mode or a control setting that is implemented in the plant control systems are excluded."

Dispute Resolution Mechanism - Change made. The SDT understands the concern that the 3rd bullet item in R9 could be potentially used by GO or TO to by-pass TP or PC requirements. The 3rd bullet item in R9 is therefore changed to: "A resubmission of the current model and accompanying information in accordance with Requirements R2, R3, R4, R5, or R6, with additional technical justification and supporting evidence to address the notification of denial or model review from the Transmission Planner."

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	No
Document Name	

Comment

The SDT did not address the structural concerns identified by the MRO NSRF Draft 1.

The MRO NSRF recommends that NERC MOD-026-1 Requirement R4, Footnote 5 be added back into the Standard as provided clarification to the phrase 'alter equipment response characteristics'.

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 0	
Dislikes 0	

Response

Change made. MOD-026-1 R4 Footnote 5 is added back into Draft 3 with adaption to the expanded MOD-026-2 scope.

For large signal disturbance, please refer to SDT’s answer in Question 4.

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

Answer	No
Document Name	

Comment

WEC Energy Group supports both the MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	

Response

See EEI and MRO NSRF responses.

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The SDT did not address the structural concerns identified by the MRO NSRF Draft 1. The MRO NSRF recommends that NERC MOD-026-1 Requirement R4, Footnote 5 be added back into the Standard as provided clarification to the phrase ‘alter equipment response characteristics’. 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 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Change made. MOD-026-1 R4 Footnote 5 is added back into Draft 3 with adaption to the expanded MOD-026-2 scope. For large disturbance, please refer to SDT’s answer in Question 4.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The term, “control mode,” in R7 should be changed to, “type of control,” as was done in R3.1. Combined cycle units frequently shift between the load setpoint control mode and firing temperature limit control mode, for example, and fossil units at very high output go from throttling to the valves-wide-open mode. These transitions alter the response to frequency disturbances, but it would be impossible to reverify models for each episode. MOD-026-2 R7 should apply only when converting a fossil unit from mechanical hydraulic to electo-hydraulic governors or making a similar change in control **type**.	
Likes 0	
Dislikes 0	

Response	
No change to the term "control mode". Alternatively, the SDT addresses the commenter's concern by adding a new footnote to add clarify over what is "the change that alters the equipment response characteristic". Please find the last sentence in the new footnote (see below) that exempts the type of control mode change described by the commenter. New Footnote 15: Such changes include: (a) exciter, voltage regulator, plant volt/var, power system stabilizer, or governor control replacement including software alterations; (b) addition or replacement of protection systems that deploy under- and over- voltage and/or under- and over-frequency elements; (c) plant digital control system addition or replacement; (d) plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, or other equipment); (e) software, firmware or setting change in the equipment (such as exciter, voltage regulator, power system stabilizer, excitation limiter, governor, plant controller, FACTs devices or IBR unit, or other equipment.) that alters its dynamic response characteristics; (f) a permanent change in the voltage or frequency control mode (such as manually switching the voltage regulator from power factor control to automatic voltage control); or (g) any other equipment change that alters its dynamic response characteristic. <u>Automatic change of control mode or a control setting that is implemented in the plant control systems are excluded.</u>	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	
Requirement 7 does not provide a specific threshold of how much of a change would require a new model. In reality, moving from a mechanical hydraulic governor to an electric hydraulic governor, changing the droop, or changing the deadband are thEdisonly major alterations. Attachment 1, Row 5 is a circular reference back to R7 and does not provide clarity. This should be corrected.	
Likes 0	
Dislikes 0	
Response	

No change is made on R7. It is not the intention of the standard to define a specific threshold of how much of a change would require a re-verified model. Alternatively, the SDT addresses the commenter's concern by adding a new footnote to provide clarify over what is "the change that alters the equipment response characteristic".

Change made. To address the duplicative timeframe information in attachment 1 and R7, all time frame information in the new draft has been moved from R7,R8/M8, R9 to Attachment 1.

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
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	
No change. It is the intention of MOD-026-2 to place the R7,R8,R9 responsibility on TP's shoulder. As described in Requirement R1, "Each Transmission Planner and its Planning Coordinator shall jointly develop dynamic model verification requirements and processes." However, the PC does not need to be explicitly mentioned in each of the requirement subparts. For example, the TP will use the acceptance criteria developed in Requirement R1.3, to review and accept the submitted information as part of Requirement R8, which does not involve the PC.	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	

At M8, the delay should be 120 calendar days, to be consistent with R8.	
Likes 0	
Dislikes 0	
Response	
Change made. To address the duplicative and/or inconsistent timeframe information in attachment 1 and R7, all time frame information in the new draft has been moved from R7, R8/M8, R9 to Attachment 1.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation agrees with proposed language. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Kristine Howie - Kristine Howie Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
Answer	Yes
Document Name	
Comment	
Constellation agrees with proposed language.	

Kristine Howie Behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE would request that the word “material” be changed to “model data and accompanying information” under R8. For R9, under the second bullet, the generators are able to provide the revised models to the Transmission Planner and technical justification and supporting evidence for maintaining the current model, 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	
Change made. The word “material” is changed to “model data and accompanying information”. Change made. The SDT understands the EEI’s concern that the 3rd bullet item in R9 could be potentially used by GO or TO to by-pass TP or PC requirements. The 3rd bullet item in R9 is therefore changed to: “A resubmission of the current model and accompanying information in accordance with Requirements R2, R3, R4, R5, or R6, with additional technical justification and supporting evidence to address the notification of denial or model review from the Transmission Planner.”	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	Yes

Document Name	
Comment	
PNM Resourced agrees with the R7, R8, and R9 language, however measure M8 does not reflect the time requirement change from 90 days to 120 days as defined in the associated requirement R8.	
Likes 0	
Dislikes 0	
Response	
Change made. To address the duplicative and/or inconsistent timeframe information in attachment 1 and R7, all time frame information in the new draft has been moved from R7, R8/M8, R9 to Attachment 1.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Please see CHPD comment further in this document regarding the term 'Change' in R7, Attachment 1, row 6. This ought to be further clarified either in the standard, supporting rationale, or other documentation from NERC.	
Likes 0	
Dislikes 0	
Response	
The SDT addresses the commenter's concern by adding a new footnote to add clarify over what is "the change that alters the equipment response characteristic". The new footnote is similar to MOD-026-1 R4 Footnote 5 with adaption to the scope expansion in this new standard.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	

Comment	
The time- period for the written response to the submitter in M8 should be changed to 120 days to match with R8.	
Likes 0	
Dislikes 0	
Response	
Change made. To address the duplicative and/or inconsistent timeframe information in attachment 1 and R7, all time frame information in the new draft has been moved from R7,R8/M8, R9 to Attachment 1.	
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	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
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	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	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	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
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	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
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	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

7. The SDT believes the language of MOD-026-2 addresses the issues outlined in the 2 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.

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
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.	
Likes 0	
Dislikes 0	
Response	
The Transmission Planner would define their acceptance criteria under R1.2. This does not mean they would need to create a full EMT case for their footprint.	

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Development of EMT models requires trained individuals and time. Therefore, SDT should consider the comments provided in Q1. Some of the detail protection and control elements described in the standard as the minimum requirements may not be useful in positive sequence simulation models. This type of requirements will force entities to allocate time and resources to develop user defined models which may not be that useful at the end, but rather make the models more complicated and difficult to maintain with software version changes. Such detailed protection and control models may be needed only for EMT models. Adding more prescriptive to minimum modeling requirements may not translate to more accuracy in the	

modeling. It significantly increases compliance costs with a minimum improvement in reliability as it may not address an actual modeling gap /concerns from the TP/PC perspective. Most likely it will put a lot of burden on the generator and transmission owners in preparing this documentation and models at the same time the burden of planners reviewing this documentation and models that may not address their concerns and some of these prescriptive models may not be used or needed by planners for their study purposes.	
Likes 0	
Dislikes 0	
Response	
The SDT added requirements and detail to MOD-026/027 based on the project scope outlined in the SAR. Some of the changes and additions will incur additional cost to implement the new standard, MOD-026-2.	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	
Do not have enough information to determine what the cost impacts will be.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
See our comment below regarding units with one-way governor response.	

Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
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	
No change. The SDT felt combining the standards will in the long run be more efficient. The SDT felt combing R1, R7-R9 under one standard and having the specifics of R2/R3, R4/R5, and R6 side by side were additionally beneficial.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The SDT did not address the structural concerns identified by the MRO NSRF Draft 1. 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 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Correct. The statement is still in the Implementation Plan.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
See MRO NSRF response.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
We encourage the SDT to coordinate model requirements and processes with other efforts, such as electromagnetic transient (EMT) modeling and validation that are being contemplated for other standards. Duplication of requirements across standards can lead to inefficiencies, the need to subsequently modify (or combine) standards, and, if the requirements are not identical, conflicts and confusion.	

Likes 0	
Dislikes 0	
Response	
Agreed. The latest revisions to MOD-026-2 will be shared with any other efforts underway with EMT modelling.	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	
The SDT did not address the structural concerns identified by the MRO NSRF Draft 1. 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 0	
Dislikes 0	
Response	
Correct. That statement is still in the Implementation Plan.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	

IID supports LPPC position that most of the registered entities (including IID) don't have the skill, experience or software to work with EMT models required by MOD-026-2. Utilities unfamiliarity on EMT modeling will take time to fix.	
Likes 0	
Dislikes 0	
Response	
This was a consideration for the Implementation Plan, having 5 years total for compliance with R6 and maintaining the 10-year periodicity.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Initial Cost Effectiveness cannot be determined at this time.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	

Response	
See MRO NSRF 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 additional, significant costs to model protection functions.	
Likes 0	
Dislikes 0	
Response	
The justification of adding protection systems is outlined in the Technical Rationale.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
The modifications do address the issues in the 2 SARs. RF notes that additional EMT model verification items are included that relate to the recently initiated Project 2022-04 EMT Modeling. The EMT project may be able to address the EMT model verification items, allowing this project moving forward.	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes the revisions are not cost effective. This version of the standard puts a substantial burden on the industry to find contractors to do a complete overhaul of testing. The proposed standard does not account for the current 10-year testing life cycle of the existing standards. There is very limited expertise available for EMT models on the Generator Owner and Transmission Planner sides, which also creates a burden by attempting to utilize the same resources.	
Likes 0	
Dislikes 0	
Response	
This was a consideration for the 5-year total compliance date in the Implementation Plan. Additionally the 10 year periodicity was maintained, see section titled, ***Initial Performance of Periodic Requirements*.**	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
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 equipment settings not a modeling issue. Requiring EMT models and simulations will add significant costs to GOs when the focus should be 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 must 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 technical justification for them on a case-by-case basis.	

The requirement to provide protection models will add significant time and dollars to submittals with little benefit to reliability studies. This will require most Generator Owners to maintain licensed copies of PSSe/PSLF as well.	
Likes 0	
Dislikes 0	
Response	
The SDT added requirements and detail to MOD-026/027 based on the project scope outlined in the SAR. Some of the changes and additions will incur additional cost to implement the new standard, MOD-026-2. EMT models are more accessible to the GO/TO around the time of commissioning. If for example, a TP makes a retroactive requirement for an IBR Facility from 5-10 years prior then that would be both costly and difficult for the GO/TO to obtain.	
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 mentioned in either SAR and implementation would not be cost effective.	
Likes 0	
Dislikes 0	
Response	
The Technical Rationale and justification in multiple NERC Disturbance Reports outline the need for EMT models.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPCO signed on to ACES comments below: The attestation proposed in R6.1 could become overly costly and, in our opinion, does not provide a good return on investment as currently written. See response to question 5 above for additional details.	
Likes 0	
Dislikes 0	
Response	
Attestations in R6.1 give the assurance that the model(s) is being provided by the OEM represent the equipment supplied.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
As outlined above in AZPS's response to Questions, 2, 3, 4, and 5 above, AZPS believes that many of the SDT's recommendations are already being addressed by other standards or will require significant additional work with minimal benefit to reliability.	
Likes 0	
Dislikes 0	
Response	
See question responses.	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	No
Document Name	
Comment	

Buckeye Power, Inc supports the comments made by ACES Power Marketing.	
Likes 0	
Dislikes 0	
Response	
See ACES response.	
Kristine Howie - Kristine Howie Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
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. Kristine Howie behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Agreed. These were considerations in the Implementation Plan. Changes were made to the Implementation Plan.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	

Many entities currently do not possess the software to perform/validate or have the personnel trained to perform EMT studies. It will take a large outlay to train people appropriately and acquire the necessary hardware and software to perform EMT studies. We estimate it will be Q2 of 2025 before we can budget for and purchase the required software and then train people adequately to perform EMT model studies. We would ask that the implementation date be pushed back for the base requirements until after that time so entities will be able to purchase the software, train their employees and develop modeling requirements prior to the enforcement date.	
Likes 0	
Dislikes 0	
Response	
Agreed. These were considerations in the Implementation Plan. Changes were made to the Implementation Plan.	
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. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Agreed. These were considerations in the Implementation Plan. Changes were made to the Implementation Plan.	
Jennie Wike - Jennie Wike Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	

Answer	No
Document Name	
Comment	
For traditional synchronous generating resources, this revision adds new requirements not previously modeled (e.g., excitation limiters and protection systems) and modifies the Applicability section to include generating facilities not previously applicable. This is a significant cost and modeling effort for synchronous generator owners. The scope of the SARs was primarily to revise MOD-026 and MOD-027 to address Transmission connected dynamic resources and IBRs. The additional R2.2 and R3.3, and changes to the Applicability section, are not directly captured in the SARs. Regarding efficiency, combining MOD-026 and MOD-027 may seem to be more efficient on the surface but in reality, these two Standards are generally performed together and combining the two Standards may not create more efficiencies.	
Likes 0	
Dislikes 0	
Response	
The addition of limiters and Protection Systems are outlined in the Technical Rationale. The SDT felt combining the two standards (MOD-026/027) will be more efficient in the long run. Plus there is not a new third standard specific to EMT model verification and validations.	
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	

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
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. CEHE believes that the required models' level of detail should be within the simulation tool's modeling capabilities and reasonable industry practices. The EMT models should only be requested/provided based on proper justification and on a case-by-case basis. Most Registered Entities do not have the historical experience or software to work with EMT models required by MOD-026-2. Utilities' unfamiliarity with EMT modeling will take many work hours from engineers or consultants, and other staff to modify all of the compliance processes already established.	
Likes 0	
Dislikes 0	
Response	
See Technical Rationale for adding EMT models.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
See EEI 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 cannot fully comment if the modifications are cost effective until the modifications are completed, but does have the following input: The additional model(s) required in Requirements R2 and R3 (example: OEL and enabled Protection System) should only be required if they are required by the Transmission Planner (TP). If they are not utilized by the TP, but still required under R2 and/or R3, the additional burden is not cost effective. The Requirement language should be updated to eliminate steps that will not be required if the TP indicates they are not required.	
Likes 0	
Dislikes 0	
Response	
List of protection systems reduced to a minimum in R2 and R3.	
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	
With respect to R6 and EMT models: A computer outfitted to run EMT modeling software is expensive due to processing power needs. EMT software is very expensive. Training engineers in house or consulting out to do the modeling is expensive. Installing equipment at BES facilities to capture large signal disturbance events is expensive. Recommend TPs analyze facilities that pose the greatest risk and let them decide if an EMT model is needed.	

With limited expertise available for EMT modeling, the cost to contracting entities will definitely be significant – the price of this service is like any other service that follows the supply/demand economic impact. As 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).”, we are in agreement with positive sequence model verification plan.	
Likes 0	
Dislikes 0	
Response	
These were considerations for the Implementation Plan, which was extended to 5 years total for newly applicable Facilities. The standard does not require that large signal disturbance testing be performed by the GO/TO. The OEM is expect to do device testing for the equipment supplied by OEM. See Technical Rationale regarding need for EMT models and the pitfall of having TP require at a later date. Agreed. There will be some cost impact to create the EMT models. See Implementation Plan section *Initial Performance of Periodic Requirements, “*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). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.”	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI supports comments provided by the NAGF.	
Likes 0	

Dislikes 0	
Response	
See NAGF response.	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
Cost impact is not clear. Reference comments to other questions, as the proposed MOD-026-2 does not appear to effectively enhance reliability or completely address the associated SARs.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
The attestation proposed in R6.1 could become overly costly and, in our opinion, does not provide a good return on investment as currently written. See response to question 5 above for additional details.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	

Answer	No
Document Name	
Comment	

Relative to validation, there is a lack of independent, quantified assessment on the effectiveness and improved reliability of the current versions of the MOD-026-1 and MOD-027-1. GOs are not part of the transmission planning process and should not function in a transmission planning role to perform model parameterization checks, usability, initialization, and interoperability assessments.

Likes 0	
Dislikes 0	
Response	

This was a consideration for the longer Implementation Plan.

TP must have those model acceptance criteria of R1.2, so the model provided by GO/TO can be used in the TP activities.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	
Comment	

NVE 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).”

NVE 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 0	
Dislikes 0	
Response	

Yes, that paragraph was maintained in the Implementation Plan. Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Additional models need to be developed, tested, and validated. There are limited resources available who can provide these services. Manufacturers may not be able to support PSCAD models development for equipment that is no longer supported or in production.	
Likes 0	
Dislikes 0	
Response	
Agreed. This was a consideration for the longer Implementation Plan, and compliance dates.	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
SPP has a concern that the cost effectiveness of this project has not been addressed. As we have reviewed the initial SAR as well as the two SARs in reference to IBRs and Transmission Connected Dynamic Reactive Resources. The concern is that each cost effectiveness section of the SARs has an unknown impact on cost.	

From our perspective, the cost of effectiveness of the proposed standard cannot be measured, because the SAR or SDT drafting team hasn't clearly addressed the potential costs of this project. SPP recommends that the drafting team structure some type of initial cost analysis to help give industry an idea about cost. Again, from our perspective, there's no clear data showing the cost impact of the project which means industry can't evaluate cost if the proposed standard provides no cost data to review.	
Likes 0	
Dislikes 0	
Response	
The SDT has attempted to create efficiency gain by combining MOD-026/027. The addition of EMT models is warranted as outlined in the Technical Rationale.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
No additional comments.	

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
As we commented on Draft 1, 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	
The SDT did not see a need for a field test. EMT models have been used by TP in studies for multiple years. Additionally a Reliability Guideline for EMT Models was recently published.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
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	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
No comment. WECC believes the applicable entities are best suited to respond to this question.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	

BHC will not respond to cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
BHC will not respond to cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
BHC will not respond to cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

Josh Combs - Black Hills Corporation - 3	
Answer	
Document Name	
Comment	
BHC will not respond to cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have 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	

ITC supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
See EEI response.	

8. ***The SDT proposes a 1-year implementation plan for Requirements R1, R7, R8, and R9, with an additional 3 years for compliance with Requirements R2-R6 for newly applicable Facilities. For existing Facilities, the Implementation Plan proposes the 10-year reoccurring periodicity is maintained from the date of previous model verification. Do you agree with the proposed implementation plan timeframes? If you think an alternate timeframe is needed, please propose an alternate implementation plan with detailed explanation*****.**

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
SPP has a concern about the implementation of this project. The concern is that there are other projects such as MOD-032, EMT as well as other projects that has an impact on modeling, studies and data collection in reference to IBRs, DERs and ESRs. The drafting team needs to take into consideration the implementation of other projects to make sure that all reliability gaps are addressed. We recommend that the drafting team coordinate with other NERC drafting teams (ie MOD-032, EMT, etc) to ensure that each effort is seamless. If not, there will be a lot of confusion on expectations, specifically, in the reliability and compliance areas.	
Likes 0	
Dislikes 0	
Response	
Revisions of MOD-026-2 are being shared with other MOD drafting teams, particularly Project 2022-04 EMT Modeling, as the projects progress.	
Tony Hua - Austin Energy - 4	
Answer	No
Document Name	
Comment	
Austin Energy supports LPC comments	

Likes 0	
Dislikes 0	
Response	
See LPPC response.	
Michael Dieringer - Austin Energy - 3	
Answer	No
Document Name	
Comment	
Austin Energy supports LPPC comments	
Likes 0	
Dislikes 0	
Response	
See LPPC response.	
Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
We believe that a 3-year implementation is too aggressive. As stated above, many of our windfarms are older than 10-years. We request a minimum of 6-year implementation for existing sites.	
Likes 0	
Dislikes 0	
Response	

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Imane Mrini - Austin Energy - 6	
Answer	No
Document Name	
Comment	
Austin Energy supports LPPC comments. Austin Energy. Segments 1,3,4,5,6	
Likes 0	
Dislikes 0	
Response	
See LPPC response.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5;	

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

Answer	No
Document Name	

Comment

SMUD and BANC support the comment of LPPC.

Likes 0	
Dislikes 0	

Response

See LPPC response.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NVE 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. NVE recommends a 5 year staged implementation.

Likes 0	
Dislikes 0	

Response

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.

- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Requirements R2-R6 should have a five-year implementation.	
Likes 0	
Dislikes 0	
Response	

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry’s feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Greg Davis - Georgia Transmission Corporation - 1

Answer	No
Document Name	

Comment

A 24-month implementation period for R1 is recommended.

Likes 0	
Dislikes 0	

Response

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9

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

Answer	No
Document Name	

Comment

AECI supports comments provided by the NAGF.

Likes 0	
Dislikes 0	

Response

See NAGF 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	
There is no way R6 could be completed in 3 years as described. 10 years would be a challenge. Equipment must be bought and installed. EMT software must be purchased and engineers must be trained on how to use it. Large signal disturbances must occur, but until equipment is installed and operational, data cannot be captured. We strongly oppose inclusion of R6, but if it is mandated, three years is woefully insufficient to complete for all applicable facilities. A 10-year phase-in period should be considered at minimum. This integration period will permit all parties the flexibility to balance the work load of the current modeling requirements for subsequent model verification along with new work resulting from this revision to MOD-026.	
Likes 0	
Dislikes 0	
Response	

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

John McCaffrey - American Public Power Association - 4 - NA - Not Applicable	
Answer	No
Document Name	
Comment	

APPA is concerned about how the proposed implementation timeframes for Project 2020-06 may align with the timeline established by the NERC work plan developed in response to FERC's Registration of Inverter-based Resources (IBR) Order and any obligations arising from FERC's pending Notice of Proposed Rulemaking (NOPR) proposing to direct NERC to modify or develop reliability standards to address perceived reliability gaps related to IBRs . The proposed MOD-026 changes are a significant effort and cost for entities. Many entities do not have the expertise to perform the work required to comply with MOD-026, and will need to contract with vendors. There are a limited number of vendors available to perform this work, as noted by other Commenter s. APPA is concerned that the IBR Order and associated IBR NOPR, will necessitate another revision to MOD-026. Back-to-back revisions to MOD-026 will negatively impact entities who already contracted the scope of work. Entities will need to revise or rush to negotiate new contracts for these additional units. In establishing the implementation timeframes for MOD-026, APPA strongly encourages the SDT to take steps to reconcile the timing of compliance obligations with any expanded or modified MOD-026 obligations resulting from the FERC proceedings so as to avoid the risk of duplicative or inefficient workstreams. Ensuring that implementation of MOD-026 aligns with any obligations resulting from the IBR Order and IBR NOPR will be more cost effective and will ultimately save time in implementing the Requirements, since contracts won't need to be modified or work re-performed.

Likes 0	
Dislikes 0	
Response	

The Applicable Facilities are stated in the current draft version. The SDT has not yet been asked to review the Applicable Facilities for IBRs based on the FERC NOPR. This would be part of the NERC Work Plan.

Joseph McClung - JEA - 1, Group Name LPPC	
Answer	No
Document Name	
Comment	

LPPC is concerned about how the proposed implementation timeframes for Project 2020-06 may align with the timeline established by the NERC work plan developed in response to FERC's Registration of Inverter-based Resources (IBR) Order and any obligations arising from FERC's pending Notice Of Proposed Rulemaking (NOPR) proposing to direct NERC to modify or develop reliability standards to address perceived reliability gaps related to IBRs. The proposed MOD-026 changes are a significant effort and cost for entities. Many entities do not have the expertise to perform the work required to comply with MOD-026, and will need to contract with vendors. There are a limited number of vendors available to perform this work, as noted by other Commenter s. LPPC is concerned that the IBR Order and associated IBR NOPR, will necessitate another revision to MOD-026. Back-to-back revisions to MOD-026 will negatively impact entities who already contracted the scope of work. Entities will need to revise or rush to negotiate new contracts for these additional units. In establishing the implementation timeframes for MOD-026, LPPC strongly encourages the SDT to take steps to reconcile the timing of compliance obligations with any expanded or modified MOD-026 obligations resulting from the FERC proceedings so as to avoid the risk of duplicative or inefficient workstreams. Ensuring that implementation of MOD-026 aligns with any obligations resulting from the IBR Order and IBR NOPR will be more cost effective and will ultimately save time in implementing the Requirements, since contracts won't need to be modified or work re-performed.

Likes 2	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre; JEA, 3, Williams Marilyn
Dislikes 0	

Response

The Applicable Facilities are stated in the current draft version. The SDT has not yet been asked to review the Applicable Facilities for IBRs based on the FERC NOPR. This would be part of the NERC Work Plan.

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

Answer	No
Document Name	

Comment

ITC supports the comments submitted by EEI

ITC has the following additional comments:

For R8, the time frame specified of 120 days seems too short for the model verification especially when it includes an EMT model and could also be based on the parameters identified in the procedure identified by TPs/PC for the verification in R1.

Likes 0	
Dislikes 0	

Response

See EEI 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 submitted by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

See EEI 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 indicates for newly applicable synchronous generating facilities (facilities with a lower MVA threshold than previously required), a phased-in implementation that is similar to what was provided in MOD-026-1 and MOD-027-1 be added to the implementation plan. This will allow applicable entities to allocate scarce resources to accommodate the addition of the newly applicable facilities.

Likes 0	
Dislikes 0	

Response	
The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback. Changes for MOD-026-2 Draft 3 • Effective date (2 years after FERC approval) applies to R1, R8, and R9 • For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date. • For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity. ○ Initial Performance of Periodic Requirements Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Kinte Whitehead - Exelon - 3	
Answer	No

Document Name	
Comment	
Exelon concurs with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE supports the comments as submitted by the Edison Electric Institute.	

Likes 0	
Dislikes 0	

Response

See EEI response.

Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC

Answer	No
Document Name	

Comment

R7 should have an additional 3 years for compliance, like R2-R6. The rationale is that if a hardware, software, firmware, control mode, or setting change to in-service equipment is made after the effective date of MOD-026-02, compliance to requirements R2-R6 (based on this change) should not happen before R2-R6 compliance date.

Also, the version of the "BES definition" that is mentioned at section A.4.2 of MOD-026-02, should be clearly stated in MOD-026-02, to avoid any misunderstanding regarding the applicability criteria. Rationale: If a new version of the "BES definition" with new applicability criteria is released in the future, a new implementation plan will be necessary to allow the implementation of the newly applicable units. This is not covered in the proposed MOD-026-02, and therefore the version of the "BES definition" should be added. If MOD-026-02 is kept as proposed, a change in the applicability criteria of the "BES definition" will cause the newly applicable units to be compliant right away, which is not possible. Another solution would be to add a new item in attachment 1 to cover a "BES definition" applicability criteria change.

Likes 0	
Dislikes 0	

Response

Change made. R7 has the same implementation timing (Compliance Date) as R2-R6.

The Applicable Facilities are stated in the current draft version. The SDT has not yet been asked to review the Applicable Facilities for IBRs based on the FERC NOPR. This would be part of the NERC Work Plan.

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	
Comment	

R7 should have an additional 3 years for compliance, like R2-R6. The rationale is that if a hardware, software, firmware, control mode, or setting change to in-service equipment is made after the effective date of MOD-26-02, compliance to requirements R2-R6 (based on this change) should not happen before R2-R6 compliance date.

Likes 0	
Dislikes 0	
Response	

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

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

Answer	No
Document Name	
Comment	

Additional implementation plan clarification is needed regarding how the proposed MOD-026-2 periodic compliance deadlines work with the current periodic requirements of MOD-026-1 and MOD-027-1. For example, per the current MOD-026-1 and MOD-027-1 a unit has verification dates being 6/1/2015 and 6/1/2022. Assuming a MOD-026-2 effectiveness date of 9/1/2024, are the deadlines of 9/1/2027 for MOD-026-2 R2 excitation system testing (three years from the effectiveness date, but more than ten years from the previous verification) and 6/1/2032 for the R3 governor testing?

Likes 0	
Dislikes 0	

Response

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

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

Comment

In general, we found the wording of the Draft 2 Implementation Plan to be confusing. See additional comments on the Implementation Plan under our response to Q9. As we commented on Draft 1, we recommend an additional 4 years for compliance with Requirements R2-R6 for newly applicable Facilities (5 years after the effective date of the applicable governmental authority's order approving the standard).

Likes 0	
Dislikes 0	

Response

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

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

Answer	No
Document Name	

Comment

Tacoma Power supports LPPC's comments.

Likes 0	
Dislikes 0	
Response	
See LPPC response.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #8.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	No
Document Name	
Comment	
Buckeye Power, Inc supports the comments made by ACES Power Marketing.	
Likes 0	
Dislikes 0	
Response	

See ACES response.

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

Answer	No
Document Name	

Comment

APPA/LPPC recommends that Project 2020-06 should be delayed to align with the timeline established by the IBR Order work plan. The proposed MOD-026 changes are a significant effort and cost for entities. Many entities do not have the expertise to perform the work required to comply with MOD-026, and will need to contract with vendors. There are a limited number of vendors available to perform this work, as noted by other Commenter s. APPA/LPPC is concerned that the IBR Order and associated IBR NOPR, will necessitate another revision to MOD-026. Back-to-back revisions to MOD-026 will negatively impact entities who already contracted the scope of work. Entities will need to revise or rush to negotiate new contracts for these additional units. Waiting a few months to ensure MOD-026 aligns with the IBR Order is more cost effective and will ultimately save time in implementing the Requirements, since contracts won't need to be modified or work re-performed.

Likes 0	
Dislikes 0	

Response

See LPPC response.

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren agrees with and supports NAGF comments.

Likes 0	
Dislikes 0	

Response	
See NAGF response.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
AZPS agrees with EEI's comments that "the rapid changes being made to require verified resource EMT models for introduction into area and regional EMT studies is out pacing the industry's ability to comply. This includes OEMs and responsible entities who are both being challenged to provide verified EMT models that are non-proprietary and broadly useful to planners. All of this requires the support of a limited number of qualified consultants and necessitates substantial training to ensure responsible entity staff."	
Likes 0	
Dislikes 0	
Response	
See EEI 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 implementation 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	
The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback. Changes for MOD-026-2 Draft 3 • Effective date (2 years after FERC approval) applies to R1, R8, and R9 • For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.	
Josh Combs - Black Hills Corporation - 3	
Answer	No
Document Name	
Comment	
BHC supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
BHC supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

See NAGF response.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHC supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
BHC supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No

Document Name	
Comment	

Duke Energy suggest a 5-year implementation plan for R2-6 and a 2-year implementation plan for R1, R7, R8, and R9. This period is needed because NERC auditors require GOs to establish program documents, procedures, test plans, work orders, etc. Duke Energy will require time to make these changes and considers the suggested timeframe too restrictive.

Likes 0	
Dislikes 0	

Response

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - <u>Initial Performance of Periodic Requirements</u>

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

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

Answer	No
Document Name	
Comment	

For existing facilities, a 1-year implementation plan does not allow adequate time for the TP/PC to develop dynamic model verification requirements and processes, nor, for software to be developed and available for industry use. If a GO's testing is due within two years, the GO would then also need to include the EMT models. BPA believes finding knowledgeable, trained resources (contractors) to provide viable, accurate models isn't feasible within this timeframe. It will take several years before resources can gain the industry knowledge, skills, and ability to provide EMT Models. This would present bottlenecks for those waiting to have viable, accurate EMT Models completed within compliance timeframes. Ultimately, this would create a rush for Generator Owners, which would then potentially cause the semination of unreliable/inaccurate data to Transmission Planners. BPA believes this creates a "cart before the horse" scenario.

For newly applicable facilities, BPA believes a feasible timeframe would be created if EMT Models were included as part of the Generation Interconnection process.

Likes 0	
Dislikes 0	

Response

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Lindsey Mannion - ReliabilityFirst - 10

Answer	No

Document Name	
Comment	

RF does not object to the implementation plan intent described in question 8. However, the language in the posted implementation plan draft is different.

The "Compliance Date for MOD-026-2 – Requirements R2, R3, R4, R5, and R6" section of the implementation plan uses the language "Applicable Entities shall not be required to comply…", which is broader than solely addressing newly applicable Facilities that were not applicable under MOD-026-1 and MOD-027-1.

As currently drafted, the implementation plan apparently retires MOD-026-1 and MOD-027-1 thirty-six (36) months prior to when Applicable Entities are required to comply with replacement requirements MOD-026-2 R2, R3, R4, and R5, creating a gap period during which neither the standards to be retired nor the replacement requirements in the new standard are enforceable.

While a phased implementation plan over a 3- or 4-year period may be appropriate for newly applicable facilities, an enforceability gap in model verification requirements for already applicable facilities may have a negative impact on transmission planning analysis quality and interconnection queue study timeliness.

Likes 0	
Dislikes 0	

Response

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

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

Answer	No
Document Name	

Comment

Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	

Response

See MRO NSRF response.

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

Answer	No
Document Name	

Comment

FirstEnergy supports EEI's Comments which state:

While EEI supports the changes being implemented in MOD-026 by the SDT, the rapid changes being made to require verified resource EMT models for introduction into area and regional EMT studies is out pacing the industry's ability to comply. This includes OEMs and responsible entities who are both being challenged to provide verified EMT models that are non-proprietary and broadly useful to planners. All of this requires the support of a limited number of qualified consultants and necessitates substantial training to ensure responsible entity staff.

The SDT should consider a 60 month implementation plan**, specifically 2-years for R1, R7, R8 and R9 and the 3 additional years for Requirement R2-R6,** that would provide responsible entities sufficient time to develop trained staff and allow affected OEMs the ability to develop non-proprietary models that more could accurately reflect the performance of the resources they are suppling to the industry.	
Likes 0	
Dislikes 0	
Likes 0	
Dislikes 0	

Response

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	

IID supports LPPC recommendation for the implementation period for R6 be extended from 36 to 48 months to allow Entities enough time to purchase, installed and be trained on EMT software, to 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 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Larry Brusseau - Corn Belt Power Cooperative - 1 - 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 0	

Dislikes 0	

Response

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

      Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1

Answer	No
Document Name	

Comment

SNPD engineers do not have experience with EMT modeling and require more time to facilitate training. SNPD proposes a 3-year implementation plan for Requirements R1, R7, R8, and R9, and 5 years for compliance with Requirements R2-R6 for newly applicable Facilities.

Likes 2	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	

Response

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
The requirement to develop acceptable electromagnetic transient (EMT) models, format, and level of detail is likely to involve the vetting, purchase, and training of applicable staff in new EMT software. Because of this we recommend a 2-year implementation plan for R1, R7, R8, and R9.	
Likes 0	
Dislikes 0	
Response	

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry’s feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.

- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

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

Answer	No
Document Name	

Comment

WEC Energy Group supports the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

See MRO NSRF comments.

Casey Perry - PNM Resources - 1,3 - WECC

Answer	No
Document Name	

Comment

PNM Resources recommends a longer implementation period for requirements R1.2 and R6. Requirement R6 needs a longer implementation period due to the time needed for the GOs to attain these models and requirement R1.2 should also be given a longer implementation period since the

Transmission Planners will need time to acquire and learn how to use EMT software. The other requirements should not require additional implementation time.	
Likes 0	
Dislikes 0	
Response	

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - <u>Initial Performance of Periodic Requirements</u>

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
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 1	Lincoln Electric System, 1, Johnson Josh

Dislikes 0	

Response

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

Implementation Plan clarification is needed regarding how the statement that compliance shall not be required until 36 months after the effectiveness date of MOD-026-2 fits with the later input that entities shall initially comply in accordance with the periodic requirements of MOD-026-1 and MOD-027-1. Take for example a unit with the latest MOD-026-1 and MOD-027-1 verification dates being 6/1/2015 and 6/1/2022 respectively, and a hypothetical MOD-026-2 effectiveness date of 9/1/2024. Are the deadlines 9/1/2027 for MOD-026-2 R2 excitation system testing (three years from the effectiveness date, but more than ten years from the previous verification) and 6/1/2032 for the R3 governor testing?

Likes 0	
Dislikes 0	

Response

Your example: For MOD-026-1, **the <u>10 year date is 6/1/2025</u>.** If MOD-026-2 Effective Date is 9/1/2024, then the Compliance Date for R2 is an additional 3 years, or **9/1/2027 (Compliance Date)**. So in this example, the later date would be the Compliance Date = 9/1/2027. For MOD-027-1, the 10 year date of MOD-026-2 R3 would be the later, so 6/1/2032.

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry's feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - <u>Initial Performance of Periodic Requirements</u>

    Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

Constellation has no additional comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Kristine Howie - Kristine Howie Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments Kristine Howie behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
On behalf of the SERC GWG: Under Effective Date: slightly ambiguous the effective dates for existing facilities. Suggest specifically calling out the 10 year re-occuring in that section	
Likes 0	
Dislikes 0	
Response	

Change made. Applicable Entities shall not be required to comply with Requirement R2, R3, R4, R5, R6, and R7 until thirty-six (36) months after the effective date of Reliability Standard MOD-026-2. **For an Applicable Entity previously performing MOD-026-1 Requirement R2 or MOD-027-1 Requirement R2 see the *Initial Performance of Periodic Requirements* section below.**

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP thanks the Standard Drafting Team for extending the Implementation Period, as we suggested in the previous comment period.	
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	

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

Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

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

Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment

Texas RE continues to seek clarity on the implementation plan. Texas RE understands the Implementation Plan as follows:

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.

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? More broadly, in Texas RE's experience, phased-in implementation plans are complex and, in general, not consistently understood by registered entities and Regions. A timeline of examples of implementation would be helpful for the SDT to provide as part of the Implementation Plan materials to avoid industry confusion and corresponding compliance issues.

Additionally, Texas RE noticed that the Implementation Plan uses the term "Applicable Entities." Since the term is capitalized, Texas RE believes that this term should be defined. The term "Applicable Entities" is neither in the NERC Glossary, nor is it defined in the proposed Standard Requirement language. Is it intended that Applicable Entities are the Functional Entities described in Section A4? If so, Texas RE recommends either making this explicit or referring specifically to the Functional Entities listed in Section A4.

Likes 0	
Dislikes 0	

Response

The scenarios above are correct based on the previous Implementation Plan. There is now 2 years from FERC approval date to Effective Date (R1, R8, R9), and an additional 3 years for Compliance Date of R2-R6 and R7.

Change made to “applicable Entities”

Timeline of examples was provided in the April 24 industry webinar for draft 3.

Link to webinar recording: https://nerc.webex.com/nerc/ldr.php?RCID=bf7679c81aed9518d35a952308cd090f

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

Answer	
Document Name	

Comment

No comment. WECC believes the applicable entities are best suited to respond to this question.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	
Document Name	

Comment

Yes.

Likes 0	
Dislikes 0	

Response

9. ***Provide any additional comments on the standard and technical rationale for the SDT to consider, if desired.***	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Daniel Roethemeyer - Vistra Energy - 5	
Answer	

Document Name	
Comment	
MOD-026/027 should remain separate and the 5% NCF exemption should remain	
Likes 0	
Dislikes 0	
Response	
The SDT has decided to move forward with combining MOD-026/027. The 5% NCF exemption is still in Attachment 1, Row 12. See change to “most recent three calendar years”	
Donald Lock - Talen Generation, LLC - 5	
Answer	
Document Name	
Comment	
The inscrutable language of MOD-027-1 Att. 1 Row 7 has generally been interpreted by GOs and the testing firms they hire as meaning that units normally able to respond only to over-frequency excursions (e.g. combined cycle STGs under sliding-pressure control) can comply via an attestation of unresponsiveness. The REs we deal with have deemed this approach to be acceptable, since (we have been told) this is what the MOD-027-1 SDT intended. A major change is being proposed in MOD-026-2 Att. 1 Row 9, however, which says that one-way-responsive units must be tested. There is little value to this new requirement, firstly because BES crises seem to always involve underfrequency events, not over-frequency. More importantly, the new models being asked for may be misleading due to reset windup. That is, controllers saturate at maximum output when an STG is running VWO, and the time required to wind down and take command of the HPT control valves generally exceeds the duration of over-frequency events. Combined cycle STGs are therefore usually unresponsive in both directions for normal operation, even though during testing one can drive upward the speed reference signal and hold it constant long enough to force a response.	
Likes 0	
Dislikes 0	
Response	

No change. It is a fact that combined-cycle STGs do not govern within the time frame of dynamic studies and that applies to both over- and under-frequency. CCPP STG governor models are usually omitted for this reason and these STGs should qualify for the exemption.

The case of wind and solar farms is different and even though they may not be able to govern during low frequency to increase power, they are required to govern during high frequency to decrease power and GOs should be required to verify the modeling of that action. Verified modeling is therefore, required in MOD-026-2 even in the case of one directional governing capability.

In addition, over frequency events could become more common in the future because of the nature of electronic loads that are beginning to appear such as big data centers and aggregate EV charging and so accurate modeling of over frequency governing cannot be overlooked.

Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD

Answer	
Document Name	

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 below 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. 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
Change made to Requirement R7. Footnote was added. The Planning Coordinator was included in the new standard to create similarity in modelling acceptance criteria and other processes of Requirement R1 across the Transmission Planners. Change made. Headers were added to each section of the requirements to help clarify which applicable Facilities are for each requirement. Each Requirement R2-R6 reference the associated applicable Facility Section. Protections and limiting functions were added since they can affect the generator/Facility dynamic response during a large signal disturbance, as described in the Technical Rationale. See Technical Rationale. The justification of addition of EMT models in Requirement R6 is outlined in the Technical Rationale.

No change. The SDT felt the language matched the MOD-027-1, R2.1.5 language closely, “Model(s) representing the prime mover, governor control system, and any other controls which impact the dynamic active power or frequency performance due to a system disturbance **(e.g. load controller),** but excluding automatic generation control;

The verbiage of the notification of acceptance or denial reference Requirement R1, so it is clear that this is part of the review and response.

Under Requirement R9, the TP still has the ability to request “a model review due to identified model or accompanying information deficiencies” outside of the normal review window, which the GO/TO is obligated to respond to.

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

The MRO NSRF recommends the following:

• 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 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry’s feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.

- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.

Casey Perry - PNM Resources - 1,3 - WECC	
Answer	
Document Name	
Comment	

Attachment 1 row 4 allows GOs to delay submission of models if a frequency excursion has not occurred. Why is the delay allowed when R3 and R5 state a stage test, or a measure disturbance can be used?

Attachment 1 row 11 should be modified to state that facilities with a commissioning date before 2020 but have been upgraded since 2020 must comply with R6.

The standard allows Generator Owner 365 days to submit models after commissioning or implementing changes. This time fame is too long given the current speed of interconnections. Transmission Planners will be forced to complete numerous studies before receiving updated models from Generator Owners that reflect what was installed. This delay could result in reliability issues that would have been appropriately identified in the generation interconnections if accurate models were available.

Likes 0	
Dislikes 0	

Response

No change. Some plants, particularly dispersed resources, are very difficult to test without a measured disturbance.

No change. This date would provide exemption for older/legacy plants.

No change. There is already industry consensus that 365 days is reasonable, even though closer to commissioning date is more desirable. Some equipment tuning is often done after commissioning and the model needs to be appropriately updated.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group supports both the MRO NSRF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
See MRO NSRF and EEI responses.	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	
Document Name	
Comment	

The MRO NSRF recommends the following:

{C}· 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

{C}· 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 0	
Dislikes 0	

Response

See MRO NSRF response.

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

Answer	
Document Name	

Comment

FirstEnergy supports EEI's Comments which state:

EEI recognizes the need for the expanded use of EMT models due to the rapid expansion of IBR resources. Since this effort affects several active NERC projects and it is essential that there is coordination to ensure there isn't overlapping, conflicting, or duplicative NERC requirements and that enforcement dates are aligned and coordinated. For this reason, the project be appropriately aligned with other approved NERC projects such as Project 2022-04 EMT Modeling, as well as other NERC projects that have elements of EMT modeling included.
The term "Large Signal disturbance" (see Requirements R6.2, R6.5, Footnote 12) should be defined to ensure a consistent understanding of the requirement where this term has been used.
EEI does not agree with the applicability date provided in Attachment 1, Row 11. Responsible entities should not be required to obtain verified EMT models for resources installed prior to the enforcement of this Reliability Standard.

Likes 0	
Dislikes 0	

Response

MOD-026-2 applies to the verification of EMT models

The term large signal disturbance is discussed in the Technical Rationale.

Change made. A specified date of January 1, 2023 is identified in Attachment 1, Row 13 (Requirement R6 exemption) which will be closer to the effective date of the standard.

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
See MRO NSRF response.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP appreciates the efforts of the Standards Drafting Team. While we agree with some aspects of what is proposed in the draft, AEP supports the SDT's overall goals and objectives. AEP requests that clarifications be made to make it clear that Row 5 in MOD-026-2 Attachment 1 is not in conflict with Row 7 of the same attachment. In the event that multiple identical units are upgraded at the same time so that they remain identical, and continue to meet the criteria of Row 7, only one unit's model would have to be verified at that time and in each 10 year period to comply with the standard, *not each unit at the time of the upgrade.* 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

No change. If the Facility/generating unit is upgraded then Requirement R7 would apply (Row 5). Then at least one applicable Facility would need to be re-verified under R7. Then the exemption under Row 9 (previously Row 7) could be applied. A new written statement would be needed to show the new equipment is identical, and only one model would need to be submitted.

No change. Correct; all BES Facilities are applicable in the new standard. The SDT has made this change clear in redline version of the standard and during industry webinars.

Lindsey Mannion - ReliabilityFirst - 10

Answer	
Document Name	

Comment

RF appreciates the opportunity to comment on this project, and we appreciate the efforts the Standard Drafting team has taken to address the scope of the two Project 2020-06 SARs approved by the Standards Committee. We request consideration of the comments submitted above, which address factors that prevent our support for the currently posted draft standard and implementation plan.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

To summarize, BPA does not agree with EMT models ever being included in a MOD-026 Reliability Standard revision. BPA recognizes that FERC is supportive of the industry including EMT models. After an EMT Model Reliability Guideline is approved, and the industry has time to absorb the information, EMT Models could be introduced in a new NERC Reliability Standard with an adequate implementation timeframe.

Likes 0	
Dislikes 0	

Response

The SDT discussed the need for EMT models in this standard. The SDT concluded that EMT models have shown to be critical for reliability.

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

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	

Dislikes 0	
Response	
See EEI responses.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	

BC Hydro offers the following comments in addition to those provided in response to drafting team's questions above.

1- Section 4.2 Facilities now references “applicable Facility” and “Facility”. BC Hydro suggests that, with the addition of “Facility” as a NERC-defined term in MOD-026, the use of “applicable Facility” is redundant.

2- With the addition of the “Facility” definition in Section 4.2. the Requirements R2, R3, R4, R5 and R6 can be streamlined for legibility.

For example, Requirement R6 can say

“For Facilities identified in Sections 4.2.3, 4.2.4.2 and 4.2.5.1, and 4.2.5.2 each …”

instead of the current wording:

“For inverter based resources (IBRs) identified in Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC identified in Section 4.2.5.1, and VSC HVDC identified in 4.2.5.2, each …”

3- The identification of the Inclusions I2, I4 and I5 of the NERC BES definition in Section 4.2 Facilities does bring clarity; however, the current wording of Section 4.2 Facilities may have a potentially unintended benefit of expanding the MOD-026 applicability beyond BES Facilities. Referring to these Inclusions without the Exclusions specified in the BES Definition will capture in scope of MOD-026-2 resources that would not be otherwise be deemed as part of BES. This appears inconsistent with the NERC Glossary Term “Facility” which is limited to BES Elements, and may be an intended consequence.

BC Hydro recommends adding the phrase “and not subject to any applicable Exclusions” in Sections 4.2.1 to 4.2.4, immediately after referencing Inclusions I2, I4 and I5.

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre

Dislikes 0	

Response

No change. The term “Facility” and “applicable Facility” is used to describe/defined within each particular standard.

No change. This description of the Facility (synchronous, IBR unit, FACTS, etc.) for each Section is added to aid the reader. Then they do not have to reference back to the Applicability section when reading the Requirement language.

Change made. Section 4.2.6 added for the exclusion of BES definition.

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

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	
The Technical Rational document for Requirement 1, Part 1.6 needs to be updated to indicate that MOD-026 Standard Requirement 1, Part1.6 now contains a 90 day requirement. AZPS notes that this effort affects several active NERC projects, and it is essential that there is coordination to ensure there isn't overlapping, conflicting, or duplicative NERC requirements and that enforcement dates are aligned and coordinated. For this reason, the project should be appropriately aligned with other approved NERC projects such as Project 2022-04 EMT Modeling, as well as any other NERC projects that have elements of EMT modeling included. AZPS does not agree with the applicability date provided in Attachment 1, Row 11. Responsible entities should not be required to obtain verified EMT models for resources installed prior to the enforcement of this Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Change made. Technical Rationale updated. The SDT is coordinating with other NERC projects that affect modeling, particularly Project 2022-04. Row 13 date has been updated from 2020 to 2023 in draft 3.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	
Document Name	

Comment	
The Standards Project webinars are beneficial for entities to understand the changes made in the recent version, and provide an opportunity for entities to ask questions or seek clarification. This second draft did not have a webinar. Due to the complicated nature and potential impacts of these Standard changes, APPA/LPPC recommends that webinars should be scheduled for subsequent postings.	
Likes 0	
Dislikes 0	
Response	
The SDT held a webinar for draft 3. Link to webinar recording: https://nerc.webex.com/nerc/ldr.php?RCID=bf7679c81aed9518d35a952308cd090f	
Kristine Howie - Kristine Howie Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
Answer	
Document Name	
Comment	
Constellation supports the comments provided by NAGF. Kristine Howie Behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE has the following additional comments:

· Texas RE recommends the language in Requirement R5 match the language in Requirement R4.

- Part 5.1 language match Requirement Part 4.1 language. Part 4.1 states “unit(s) **and** power plant controller” while Part 5.1 says “…unit(s)**,** power plant controller”.
- Requirement Part 5.1 also does not have a footnote describing IBR unit as in Requirement Part 4.1.
- Requirement Part 4.2 states “…associated reactive power control system” while Requirement Part 5.2 states “…associated active power/frequency control…”

In Section A5, the title of the Implementation Plan is incorrect. It should read “See Project 2020-06 Verifications of Models and Data for Generators Implementation Plan.”

The implementation plan shows Planning Authority in the Applicable Entities section; this should be changed to Planning Coordinator to match the applicability in Reliability Standard Section 4.

Likes 0	
Dislikes 0	

Response

Changes made to R4.1/R5.1 and R4.2/R5.2 for consistency of language.

Change made for Implementation Plan title in Section A5.

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

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #9.

Likes 0	
Dislikes 0	

Response	
See EEI response.	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation supports the comments provided by NAGF. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
See NAGF response.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	
Document Name	
Comment	
Tacoma Power suggests replacing the use of the “365 calendar days” terminology with 12 calendar months. This greatly simplifies the scheduling and aligns with MOD-025. Tacoma Power supports LPPC’s comments regarding webinars.	
Likes 0	
Dislikes 0	

Response	
The SDT used “calendar days” when the activity needed to be completed within a certain number of days and less than a year. The SDT held a webinar for draft 3. Link to webinar recording: https://nerc.webex.com/nerc/ldr.php?RCID=bf7679c81aed9518d35a952308cd090f See response to LPPC comments.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	MOD-026-2 Draft 2 Implementation Plan - Suggested Edits.docx
Comment	
As we commented on Draft 1, our preference is to keep MOD-026 and MOD-027 as two separate standards. Additional comments on Draft 2 of the Implementation Plan are included in the attachment.	
Likes 0	
Dislikes 0	
Response	

The SDT updated timelines in MOD-026-2 Draft 3 based on the industry’s feedback.

Changes for MOD-026-2 Draft 3

- Effective date (2 years after FERC approval) applies to R1, R8, and R9
- For newly applicable units, Compliance Date paragraph applies. Compliance Date for R2-R6, R7 is 3 years after the effective date.
- For entities already performing MOD-026/027-1 R2, Initial Performance of Periodic Requirements paragraph applies. This maintains the 10 year periodicity.
    - Initial Performance of Periodic Requirements

  Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 based upon the periodic timeframes (before the 10-year anniversary) of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2). Applicable Entities shall initially comply with MOD-026-2 Requirement R6 by the periodic

timeframe associated with the performance of MOD-026-2 Requirement R4 or performance of MOD-026-2 Requirement R5, whichever is sooner. 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.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	
Document Name	
Comment	

1. Equivalent Unit Verification Condition

At rows 1 and 7 of attachment 1 of MOD-026-02, some changes in the verbiage have been made since last version to avoid confusion around the "Equivalent Unit" topic. At row 7 however, more clarification is still needed to indicate when this row applies. For example, does it apply to row 1 (initial verification), row 2 (newly commissioned facility), row 3 (subsequent verification) and row 5 (change to in-service equipment)? If it applies to all the other rows, please add text to mention it.

2. Unit vs Facility

At row 8 of attachment 1 of MOD-026-02, in the "Verification Condition" column, term "unit or Facility" is used. This differs from all other sections where "Unit" has been replaced by "Facility".

Also, at row 7, term “unit” is used; should it be “Facility” instead?

3. Non-responsive facility

At row 9 of attachment 1 of MOD-026-02, in the “Required Action” column, last paragraph is unclear and should be deleted, as it does not bring any added value. Row 8, which has similar content than row 9, does not include this unnecessary paragraph.

Likes 0	
Dislikes 0	

Response

Change made. Row 7, Existing, new, or upgraded generating unit or synchronous condenser that is equivalent to another unit(s) at the same physical location.

No change to unit/Facility verification comment.

Change made. Perform verification per the periodicity specified in Row 2 for a “Newly commissioned Facility” (or new equipment) if the exemption condition no longer applies.

Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC

Answer	
Document Name	

Comment

1. Equivalent Unit Verification Condition

At rows 1 and 7 of attachment 1 of MOD-026-02, some changes in the verbiage have been made since last version to avoid confusion around the “Equivalent Unit” topic. At row 7 however, more clarification is still needed to indicate when this row applies. For example, does it apply to row 1 (initial verification), row 2 (newly commissioned facility), row 3 (subsequent verification) and row 5 (change to in-service equipment)? If it applies to all the other rows, please add text to mention it.

2. Unit vs Facility

At row 8 of attachment 1 of MOD-026-02, in the "Verification Condition" column, term "unit or Facility" is used. This differs from all other sections where "Unit" has been replaced by "Facility".

Also, at row 7, term "unit" is used; should it be "Facility" instead?

3. Non-responsive Facility

At row 9 of attachment 1 of MOD-026-02, in the "Required Action" column, last paragraph is unclear and should be deleted, as it does not bring any added value. Row 8, which has similar content than row 9, does not include this unnecessary paragraph.

Likes 0	
Dislikes 0	

Response

Change made. Row 7, Existing, new, or upgraded generating unit or synchronous condenser that is equivalent to another unit(s) at the same physical location.

No change to unit/Facility verification comment.

Change made. Perform verification per the periodicity specified in Row 2 for a "Newly commissioned Facility" (or new equipment) if the exemption condition no longer applies.

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

CEHE supports the comments as submitted by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

See EEI response.	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
1. Seminole noticed that the Standard drafting team did not provide a redline from last approved. This makes reviewing all the changes much more difficult. Seminole had believed NERC had adopted a process by which redlines from last approved would be provided with each additional ballot – which this is. Has NERC modified its ballot process and no longer intends to post redlines from last approved, and if not, why was a redline from last approved not posted in this additional ballot? 2. Because the model process verifications detailed in Requirement R2 may involve multiple BCAs, e.g., excitation system, protection systems, etc., if the model verification involve medium impact BCAs, will these actions fall under CIP-013 vendor risk reviews if the verifications are contracted out? 3. Some of the information that is being submitted to the TP and PC entities could be considered CEII. Can the SDT detail out how CEII protections from FERC are applied to these submissions?	
Likes 0	

Dislikes 0	
Response	

Because of the merge from MOD-026/027 providing a redline to last approved did not seem valuable. This is why a mapping document was provide as an alternative, to the requirement language could be seen side-by-side. The mapping document was provided in the posting documents.

No change. The compliance with CIP-013 and other CIP standards are not in-scope for this project.

No change. Believe that appropriate NDA's are put in place between the parties exchanging the information needs to be managed or controlled in a particular way. This can be specified by the TP/PC in Requirement R1, if needed.

Kinte Whitehead - Exelon - 3

Answer	
Document Name	
Comment	

Exelon concurs with comments submitted by EEI.

Likes 0	
Dislikes 0	
Response	

See EEI response.

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	
Comment	

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

See EEI 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 agrees with the input provided by EEI on:

1 - The need to expand the use of EMT models due to the rapid expansion of IBR resources and the recommendation on the coordination between NERC projects to avoid overlap, conflicts, or duplicative NERC Requirements and enforcement dates.

2 - That the term “Large Signal disturbance” (see Requirements R6.2, R6.5, Footnote 12) should be defined to ensure a consistent understanding of the requirement where this term has been used.

3 - The applicability date provided in Attachment 1, Row 11 should not be provided for resources installed before the enforcement of this Reliability Standard.

In addition, as noted in the July 2022 input provided by PG&E, we and other entities have currently 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 again respectfully requests that the project team add additional language to Attachment 1 that allows for grandfathering of existing exemptions similar to MOD-27-1. This will allow entities to avoid having to re-apply under MOD-026-2, which eliminates administrative and operational burdens that can be avoided.

Likes 0	
Dislikes 0	

Response

See EEI response.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	
Document Name	
Comment	
1. Seminole noticed that the Standard drafting team did not provide a redline from last approved. This makes reviewing all the changes much more difficult. Seminole had believed NERC had adopted a process by which redlines from last approved would be provided with each additional ballot – which this is. Has NERC modified its ballot process and no longer intends to post redlines from last approved, and if not, why was a redline from last approved not posted in this additional ballot? 2. Because the model process verifications detailed in Requirement R2 may involve multiple BCAs, e.g., excitation system, protection systems, etc., if the model verification involve medium impact BCAs, will these actions fall under CIP-013 vendor risk reviews if the verifications are contracted out? 3. Some of the information that is being submitted to the TP and PC entities could be considered CEII. Can the SDT detail out how CEII protections from FERC are applied to these submissions?	
Likes 0	
Dislikes 0	
Response	
1. Because of the merge from MOD-026/027 providing a redline to last approved did not seem valuable. This is why a mapping document was provide as an alternative, to the requirement language could be seen side-by-side. The mapping document was provided in the posting documents. 2. No change. The compliance with CIP-013 and other CIP standards are not in-scope for this project. 3. No change. Believe that appropriate NDA's are put in place between the parties exchanging the information needs to be managed or controlled in a particular way. This can be specified by the TP/PC in Requirement R1, if needed.	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	

Document Name	
Comment	
Portland General Electric Company supports the comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
See EEI response.	
Joseph McClung - JEA - 1, Group Name LPPC	
Answer	
Document Name	
Comment	

The Standards Project webinars are beneficial for entities to understand the changes made in the recent version, and provide an opportunity for entities to ask questions or seek clarification. This second draft did not have a webinar. Due to the complicated nature and potential impacts of these Standard changes, LPPC recommends that webinars should be scheduled for subsequent postings.	
Likes 2	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre; JEA, 3, Williams Marilyn
Dislikes 0	
Response	
The SDT held a webinar for draft 3. Link to webinar recording: https://nerc.webex.com/nerc/ldr.php?RCID=bf7679c81aed9518d35a952308cd090f	
John McCaffrey - American Public Power Association - 4 - NA - Not Applicable	
Answer	
Document Name	
Comment	
APPA members report that the Standards Project webinars are beneficial for entities to understand the changes made in the recent version, and provide an opportunity for entities to ask questions or seek clarification. This second draft did not have a webinar. Due to the complicated nature and potential impacts of these Standard changes, APPA recommends that webinars should be scheduled for subsequent postings.	
Likes 2	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre; JEA, 3, Williams Marilyn
Dislikes 0	
Response	
The SDT held a webinar for draft 3. Link to webinar recording: https://nerc.webex.com/nerc/ldr.php?RCID=bf7679c81aed9518d35a952308cd090f	
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 does not agree with the applicability date provided in Attachment 1, Row 11. Responsible entities should not be required to obtain verified EMT models for resources installed prior to the enforcement of this Reliability Standard. EMT models should be required only for resources meeting all these criterion: a) specifically identified within Requirement R6, b) commissioned after the approval date of this Reliability Standard, and c) specifically identified by the TP and/or PC.

Attachment 1, Row 9 changes the original scope of units responsive to frequency disturbances from bidirectional inclusion to unidirectional inclusion. Many generating units and facilities operate at maximum MW output conditions and cannot provide additional MW for low frequency disturbances (solar, wind, steam turbines at valves wide open conditions, combustion turbines at operating at exhaust gas temperature limits, BESS systems operating at the maximum charge condition, etc.). Requiring modeling of these situations is unproductive. The transmission planners on the original standard drafting team for MOD-026-1, and MOD-027-1 indicated that they are not interested in modeling over frequency conditions, so wording was added to Attachment 1, Row 7 of MOD-027-1 to provide model verification exemption for unidirectional responding units (**does not respond to both** over and under frequency events). What is the basis for changing this position particularly for units which are unidirectional in the response capability?

Likes 2	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre; JEA, 3, Williams Marilyn
Dislikes 0	

Response

The SDT updated row 13 date from January 1, 2020 to January 1, 2023.

Attachment 1, row 9: Arguably, all generation can be run at 100% output, and therefore could be exempted under this exception if the requirement to model is only for units that are capable of responding in both directions. The intent is to exempt units that by design or standard operating practice do not respond to frequency at all, such as combined cycle steam units in inlet pressure control or 100% open control valves, as opposed to normal 100% available dispatch, which can encompass all generation types.

Marty Watson - Santee Cooper - 5, Group Name Santee Cooper

Answer	
Document Name	

Comment

The Standards Project webinars are beneficial for entities to understand the changes made in the recent version and provide an opportunity for entities to ask questions or seek clarification. This second draft did not have a webinar. Due to the complicated nature and potential impacts of these Standard changes, Santee Cooper recommends that webinars should be scheduled for subsequent postings.	
Likes 0	
Dislikes 0	
Response	
The SDT held a webinar for draft 3. Link to webinar recording: https://nerc.webex.com/nerc/ldr.php?RCID=bf7679c81aed9518d35a952308cd090f	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	
Document Name	
Comment	
There are instances where both the PC and TP should be applicable to the requirement, but the SDT appears to point only to the TP. It is recommended that the SDT review the requirements and add both PC and TP where applicable.	
Likes 0	
Dislikes 0	
Response	
No change. For Requirement R1 the TP & PC are both applicable entities. For Requirement R8, the TP needs to be the only entity that review the models and information.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	

The SRC wants to thank the Standard Drafting Team for all their dedicated Project work and appreciates the recent drafted changes in organizing the data of Synchronized Facilities and Invertor Based Resource Facilities.

Requesting two additional Requirements:

R10. Each Transmission Planner shall send a Generator Owner or Transmission Owner a written notice to request the model review and verification when:

10.1. There is a mismatch between the simulation result and dynamic event recorded data or PMU data; or

10.2. A technical concern related to a device setting, model parameter value, or the control loop in the dynamic model.

R11. A Transmission Owner or Generation Owner shall provide the evidence in response to R10 for the applicable unit. The evidence may consist of the following:

- Simulation results and recorded event data demonstrating the simulated unit or plant response does not match the measured unit or plant response; or

- Analysis on dynamic model parameter setting or Control loop analysis.

Each Generator Owner or Transmission Owner receiving a notification of denial under Requirement R8 or a model review request from its Transmission Planner for a model review due to identified model or accompanying information deficiencies shall provide a written response to its Transmission Planner within 90 calendar days of receiving a notification or request, in accordance with the periodicity in MOD-026-2 Attachment 1.

Project 2022-04 EMT Modeling SAR recommends that verification and submittal by the GO occurs prior to commercial operation; whereas the MOD-026-02 draft allows for 365 calendar days *after* the commissioning date. However, this can lead to reliability issues not being identified during interconnection studies. Is the SDT’s intention to leave addressing this issue to the new drafting team for Project 2022-04 and no alignment or coordination is necessary?

The SRC recommends including the following items in an Implementation Guidance document:

For Section 1.1: Acceptable positive sequence dynamic Model list and level of detail should be based on NERC Eastern Interconnection Reliability Assessment Group (ERAG) or Acceptable Models Working Group (AMWG), Transmission Planner (TP) provided format the new work group that NERC is forming; i.e. the AMWG. Language should also allow the Planning Coordinator (PC) or TP to modify the NERC ERAG listing for acceptable models if necessary. The SRC would also like the PC or TP to have the ability to modify the NERC ERAG/AMWG listing for acceptable models, including user-defined models.

For Section 1.2: The SRC is unsure how a NERC EMT model list would be maintained. Most PSCAD models are uniquely developed for equipment and are black box models with limited modeling information other than inputs and outputs. Once more information is known, consideration should be given as to how acceptable Electromagnetic Transient (EMT) Model list and level of detail should be maintained. Language should also allow the PC or TP to modify the NERC-approved listing of acceptable models, if necessary.	
Likes 0	
Dislikes 0	
Response	
No change. The SDT does not want to add additional requirements. The Transmission Planner should be conducting a thorough review of the information under Requirement R8, based on the acceptance criteria defined from Requirement R1. In Requirement R9, "Each Generator Owner or Transmission Owner shall provide a written response to its Transmission Planner after receiving a notification of denial under Requirement R8 or a request from its Transmission Planner for a model review due to identified model or accompanying information deficiencies, within the timeframe in MOD-026-2 Attachment 1." A recent Reliability Guideline for EMT Models was published by the EMT Task Force. The SDT does not plan to create Implementation Guidance for MOD-026-2 based on the ongoing efforts of the IRPS and EMTTF.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	

Document Name	
Comment	

a. The technical criteria document is not adequate to show why the items requested are necessary. It just states that they are necessary. There is no data supported study or calculation that shows why these requested items are necessary for reliability.

b. There seems to be no technical basis and method to why EMT models are beneficial.

c. There is no evident technical justification as to why adding outer-loop controls, limiters, and protection into existing models would be beneficial for reliability.

d. There needs to be an assessment of the BES established models per the current versions of the MOD-026 and MOD-027 standards and see how they have been implemented by the TPs. Based on this assessment, we can identify gaps and start forming a technical justification for improvement.

e. The SDT seems to have non- technical consensus to propose these changes continent wide. It would be advantageous to pursue a project of technical justification internally at NERC, Industry Research institutes like EPRI, or Academic Institutions with capacity.

Likes 0	
Dislikes 0	

Response

The rationale for the addition of EMT model requirements is outlined in the Odessa Disturbance report, MOD-026-2 Technical Rationale, and Reliability Guideline for EMT Models.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	
Comment	

NVE recommends the following:

NVE suggests replacing the use of the “365 calendar days” terminology with 12 calendar months. This greatly simplifies the scheduling and aligns with MOD-025.

NVE 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 0	
Dislikes 0	
Response	
See MRO NSRF response.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	
Document Name	
Comment	
The Standards Project webinars are beneficial for entities to understand the changes made in the recent version, and provide an opportunity for entities to ask questions or seek clarification. This second draft did not have a webinar. Due to the complicated nature and potential impacts of these Standard changes, LPPC recommends that webinars should be scheduled for subsequent postings.	
Likes 0	
Dislikes 0	
Response	
The SDT held a webinar for draft 3. Link to webinar recording: https://nerc.webex.com/nerc/ldr.php?RCID=bf7679c81aed9518d35a952308cd090f	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	

Comment	
Consideration of Comments suggestion - While due to the similar nature of multiple comments received during the initial ballot and comment period, the SDT has chosen to respond to comments in summary format, this makes it difficult/time consuming for the member to locate where their comments have been consider and if they have been adequately position.	
Likes 0	
Dislikes 0	
Response	
The SDT attempted to respond to all comments received from this posting.	

Comments submitted by GE

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.

☐ Yes
☒ No

Comments:

- Better clarification is needed for direction on when updated models (positive sequence and EMT) are required. Manufacturers will necessarily update firmware for improved features and accuracy, as well as possible bug fixes. Provided these improvements do not affect electrical performance, these changes should be allowed without re-submission or this will risk delaying helpful software updates. New models and validation should not be required for modifications that do not reflect any material electrical performance impact. Suggest modifying the language in R7 to read "…within 180 calendar days of making a hardware, software, firmware, control modes or setting change…that alters the equipment response characteristic *and results in a material electrical performance impact*…in accordance with MOD-026-2 Attachment 1.
- Better clarification is needed for the definition of "validation" specific to this standard in Footnote 9. While it is clear that validation incudes the comparison of site results to the model responses, it may not be entirely clear that this activity can include calibration of the model prior to submission. Suggest modifying the language in Footnote 9 to read "For the purposes of this Reliability Standard, the term "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. *This activity includes the calibration of the model to match the testing or monitoring results, if necessary*. *This may be required, for example, due to the uncertainty of grid strength, or proximity of other IBR plants.*

- Many OEM's maintain user-defined models that are most applicable to their equipment. Language should be added to ensure that Generator Owners can provide these as acceptable positive sequence models, and/or that the validation of generic models may be limited as OEMs do not develop the structure of generic models, only a parameterization.

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.

   ☐ Yes
   ☒ No

   Comments:

   - Better clarification is needed for the definition of large signal disturbance in R6.2. As there does not appear to be a definition in the NERC glossary that could be referenced, suggest that it could be added here, likely in a footnote, to ensure that the understanding of large signal disturbances is clear to all parties for the purposes of validation (fault types, fault depths, governor responsive events etc).

Comments submitted by EEI

1. Do you agree as a whole that Draft 2 of MOD-026-2 is an improvement to Draft 1? If you do not agree, please provide an explanation.

   ☐ Yes
   ☒ No

   Comments: While the changes made to MOD-026-2 are an improvement, we still do not support Draft 2 because of the concerns described in our responses to Questions 2, 4, 5, 6 & 9 .

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.

   ☐ Yes
   ☒ No

   Comments: EEI does not support the proposed language for R1 because (see comments below and suggested edits to Requirement R1 in boldface):

   - R1.2 is insufficiently clear as to EMT requirements. While Footnote 2 provides clarity, clarifications contained in footnotes are often missed. EEI suggests language that we believe generally aligns with SDT intent but is not contained in a footnote.
   - R1.6 does not provide sufficient time for GOs and TOs to obtain models needed by the TP and PC. We suggest 180 days.

   R1. Each Transmission Planner and its Planning Coordinator, shall jointly develop dynamic model verification requirements and processes. The dynamic model verification 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: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

1.1. Acceptable positive sequence dynamic models, format, and level of detail;

1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail **for resources specifically identified within Requirement R6 only, and commissioned after the approval date of this Reliability Standard, and specifically identified by the TP and/or PC**;

1.3. Acceptance criteria used by the Transmission Planner to determine disposition under 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;

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 database for an existing Facility owned by the Generator Owner or Transmission Owner within **180** days of receiving a written request.

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.

☒ Yes
☐ No

Comments: EEI supports the revised language contained in Requirements R2 and R3.

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.

☒ Yes
☐ No

Comments: EEI supports the proposed language in Requirements R4 and R5.

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.

☐ Yes
☒ No

Comments: EEI suggests the following changes in boldface to Requirement R6, noting that the information in the footnotes should be moved out of the footnotes into the body of the Reliability Standard. Additionally, attestations are unenforceable on OEMs because they are non-registered entities. A better solution would be to include model requirement in OEM contracts moving forward.

R6. For applicable units of inverter based resources (IBRs) per identified in Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per identified in Section 4.2.5.1, and VSC HVDC per identified in 4.2.5.2, **commissioned after the date identified in Attachment 1, Row 11, the responsible** Generator Owner or Transmission Owner shall provide **an OEM** verified EMT model(s), **that includes all OEM supplied** 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)model(s) and accompanying information shall include at a minimum the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

6.1. **Model(s) that contain inverter control modes, control blocks, and protections represented, as applicable and be representative and accurate of the equipment installed at the generation resource.**;

6.2. Device test 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;

6.2.1 A device test that is hardware specific may include a factory type test, hardware in the loop test, or other manufacture manufacturer test to ensure the EMT model's large signal disturbance response emulates the supplied equipment to the extent possible, noting that even detailed EMT models of IBR plants, invariably have certain necessary approximations and limitations.

6.3. **OEM supplied EMT facility** model and with 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 **that conforms to the following**;

6.3.1 Models are to have the protections and controls that act on voltage, frequency, and/or current, or act on quantities derived from voltage, frequency, and/or current, which directly trip the IBR unit(s) or plant, or limit active/reactive output of the IBR unit or plant represented in the supplied EMT facility model. (*Examples of protections that should be included are IBR unit DC reverse current, DC bus over- and under-voltage, DC voltage unbalance, DC overcurrent, AC over- and under-voltage protection (instantaneous and RMS), AC overcurrent, over- and under-frequency protection, feeder (equivalent) AC over- and under-voltage, feeder (equivalent) over- and under-frequency, PLL (or equivalent) loss of synchronism, and phase jump tripping*.)

6.3.2 Model shall be non-proprietary to ensure compatibility with a wide range of modeling software.

6.4. Validation of the Facility EMT model response using the recorded response for a dynamic volt or VAR reactive power or voltage event, and for a dynamic active power or frequency event in which the power plant controller's or other Facility active power controller's perceived frequency deviates per Attachment 1, Note 1, resulting from either a staged test or a system disturbance; and

6.4.1 Exclusion: LCC HVDC facilities are excluded from the dynamic voltage or VAR event portion of the requirement.

6.5. Documentation 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.

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.

☐ Yes
☒ No

Comments: The model verification periodicity information contained in Requirements R7, R8 and R9 should be removed in favor of the information provided in Attachment 1. Duplicative periodicity information in these requirement adds unnecessary confusion as to entity obligations. For example:

Requirement R7 states updated verified model(s) or a plan to verify the model per R2, R3, R4, R5 or R6 is to be submitted to the TP within 180 calendar days, while Attachment 1, Row 5 states 180 days is required unless a plan is submitted, then 365 days after submission of a plan is allowed. To avoid this conflict, all model verification periodicity should only be in attachment 1.

Deletion of Footnote 5, MOD-026-1, Requirement 4 (*R4 has been mapped to R7*): EEI is concerned that the deletion of footnote #5 from the MOD-026-1 (i.e., not included in the current draft) has created an area of possible compliance ambiguity and risk for responsible entities. This footnote was previously included in MOD-026-1, R4 to provide clarity over what kind of changes "that alter the equipment response characteristics" are in scope. Moreover, the deletion of this footnote leaves auditors and responsible without clear direction as to the intended scope. For this reason, we ask the SDT to reconsider the deletion of footnote 5 (from MOD-026-1) or to add similarly clarifying language to the next draft.

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

7. The SDT believes the language of MOD-026-2 addresses the issues outlined in the 2 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.

☐ Yes
☐ No

Comments: *EEI will not provide comments on the cost effectiveness of the proposed changes.*

8. The SDT proposes a 1-year implementation plan for Requirements R1, R7, R8, and R9, with an additional 3 years for compliance with Requirements R2-R6 for newly applicable Facilities. For existing Facilities, the Implementation Plan proposes the 10-year reoccurring periodicity is maintained from the date of previous model verification. Do you agree with the proposed implementation plan timeframes? If you think an alternate timeframe is needed, please propose an alternate implementation plan with detailed explanation.

☐ Yes
☒ No

Comments: While EEI supports the changes being implemented in MOD-026 by the SDT, the rapid changes being made to require verified resource EMT models for introduction into area and regional EMT studies is out pacing the industry's ability to comply. This includes OEMs and responsible entities who are both being challenged to provide verified EMT models that are non-proprietary and broadly useful to planners. All of this requires the support of a limited number of qualified consultants and necessitates substantial training to ensure responsible entity staff. The SDT should consider a 60 month implementation plan**, specifically 2-years for R1, R7, R8 and R9 and the 3 additional years for Requirement R2-R6,** that would provide responsible entities sufficient time to develop trained staff and allow affected OEMs the ability to develop non-proprietary models that more could accurately reflect the performance of the resources they are suppling to the industry.

9. Provide any additional comments on the standard and technical rationale for the SDT to consider, if desired.

Comments: EEI recognizes the need for the expanded use of EMT models due to the rapid expansion of IBR resources. Since this effort affects several active NERC projects and it is essential that there is coordination to ensure there isn't overlapping, conflicting, or duplicative NERC requirements and that enforcement dates are aligned and coordinated. For this reason, the project be appropriately aligned with other approved NERC projects such as Project 2022-04 EMT Modeling, as well as other NERC projects that have elements of EMT modeling included.
The term "Large Signal Disturbance" (see Requirements R6.2, R6.5, Footnote 12) should be defined to ensure a consistent understanding of the requirement where this term has been used.

EEI does not agree with the applicability date provided in Attachment 1, Row 11. Responsible entities should not be required to obtain verified EMT models for resources installed prior to the enforcement of this Reliability Standard.

End of Report