NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2020-06 Verifications of Models and Data for Generators | MOD-026-2 - Draft 1

Comment Period Start Date: 5/22/2025

Comment Period End Date: 6/18/2025

Associated Ballot(s): 2020-06 Verifications of Models and Data for Generators MOD-026-2 – Verifications of Models and Data IN 1 ST
2020-06 Verifications of Models and Data for Generators MOD-026-2 – Verifications of Models and Data | Non-binding Poll IN 1 NB
2020-06 Verifications of Models and Data for Generators MOD-026-2 – Verifications of Models and Data | Implementation Plan IN 1 OT

There were 77 sets of responses, including comments from approximately 191 different people from approximately 126 companies representing 8 of the Industry Segments as shown in the table on 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 Manager of Standards Information, Nasheema Santos (via email) or at (404) 290-6796.

Questions

1. Do you believe there are alternatives or more cost-effective options to address the recommendations in FERC Order No. 901? If so, please provide your recommendation and, if appropriate, technical or procedural justification.

2. Do you agree that the proposed footnote term "verified models," modified from the previous accepted standard MOD-026-1, is clear and understandable? If you do not agree, or recommend further changes, please explain.

3. Do you agree that the proposed implementation plan represents a reasonable period to implement MOD-026-2 consistent with FERC's directives to implement all requirements by 2030? If you do not agree, or recommend further changes, please explain.

4. Do you agree that the proposed MOD-026-2 draft, together with MOD-033-3 draft, fulfills the FERC Order No. 901 Milestone 3 directive in P85. "to require Bulk Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners' disturbance monitoring equipment"? If you do not agree or believe there is a gap in fulfilling this directive, or recommend further changes, please explain.

5. Provide any additional comments, including a detailed explanation of any recommended revisions, for the Drafting Team 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	1,3,5	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
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					George Brown	Pattern Operators LP	5	MRO
					Amy Key	MidAmerican Energy Company (MEC)	1	MRO

						Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
						Michael Ayotte	ITC Holdings	1	MRO
						Peter Brown	Invenergy	5,6	MRO
						Angela Wheat	Southwestern Power Administration	1	MRO
						Joshua Phillips	Southwest Power Pool	2	MRO
						Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
						Hayden Maples	Evergy	1,3,5,6	MRO
						Kirsten Rowley	MISO	2	MRO
						Andrew Coffelt	Kansas City Board of Public Utilities	1,3,5,6	MRO
Santee Cooper	Chris Wagner	1,3,5,6			Santee Cooper	Weijian Cong	Santee Cooper	1,3,5,6	SERC
						Chris Wagner	Santee Cooper	1,3,5,6	SERC
						Diana Scott	Santee Cooper	1,3,5,6	SERC
						Paul Camilletti	Santee Cooper	1,3,5,6	SERC

WEC Energy Group, Inc.	Christine Kane	3,4,5,6		WEC Energy Group	Christine Kane	WEC Energy Group, Inc.	3	RF
					Michelle Hribar	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
					Candace Morakinyo	WEC Energy Group, Inc.	4	RF
Exelon	Daniel Gacek	1,3		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
Con Ed - Consolidated Edison Co. of New York	Dermot Smyth	1,3,5,6	NPCC	Con Edison	Dermot Smyth	Con Edison Company of New York	1,3,5,6	NPCC
					Edward Bedder	Orange & Rockland		NPCC
Public Utility District No. 1 of Chelan County	Diane E Landry	1,3,5,6		CHPD	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Anne Kronshage	Public Utility District No. 1 of Chelan County	6	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
Tacoma Public	Jennie Wike	1,3,4,5,6	WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC

Utilities (Tacoma, WA)					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					John Nierenberg	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,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	James Shultz	Hoosier Energy Electric Cooperative	1	RF
					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Kris Carper	Arizona Electric Power	1	WECC

						Cooperative, Inc.		
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Nikki Carson-Marquis	Minnkota Power Cooperative, Inc.	1	MRO
					Jasmine Morris	Southern Maryland Electric Cooperative	3	RF
					Kylee Kropp	Sunflower Electric Power Corporation	1	MRO
Black Hills Corporation	Josh Schumacher	1,3,5,6		Black Hills Corporation Segments 1, 3, 5, 6	Trevor Rombough	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
					Josh Schumacher	Black Hills Corporation	6	WECC
Eversource Energy	Joshua London	1,3		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
	Joshua Phillips	2		PJM, MISO, SPP, NYISO	Joshua Phillips	Southwest Power Pool	2	MRO

Southwest Power Pool, Inc. (RTO)				joint comments	Elizabeth Davis	PJM	2	RF
					Adrian Harris	MISO	2	MRO
					Gregory Campoli	New York Independent System Operator	2	NPCC
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		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
DTE Energy - Detroit Edison Company	Mohamad Elhusseini	3,5		DTE Energy	Mohamad Elhusseini	DTE Energy	5	RF
					Patricia Ireland	DTE Energy	4	RF
					Marvin Johnson	DTE Energy - Detroit Edison Company	3	RF

Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC

					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC

					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
					Emma Halilovic	Hydro One	1,3	NPCC
					Philip Nichols	National Grid	1	NPCC

					Emma Halilovic	Hydro One	1,3	NPCC
					Caver Powers	Utility Services	5	NPCC
Dominion - Dominion Virginia Power	Steven Belle	1,3		Dominion	Steven Belle	Dominion Energy	1	NA - Not Applicable
					Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Sacramento Municipal Utility District	Tim Kelley	1,3,4,5,6	WECC	SMUD and 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

1. Do you believe there are alternatives or more cost-effective options to address the recommendations in FERC Order No. 901? If so, please provide your recommendation and, if appropriate, technical or procedural justification.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Until concerns mentioned below in preceding responses are resolved, FirstEnergy cannot determine If there are alternatives or more cost-effective options to fulfil compliance obligations of this proposed standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name CHPD	
Answer	No
Document Name	
Comment	
CCPUD believes that the changes to MOD-026-2 is cost-effective for IBRs only. The draft addresses FERC No. 901 regarding IBRs, however, there are consequences to the utilities that do not currently have IBRs. For companies that maintain traditional/legacy units and have established internal controls to maintain compliance, there will be added costs.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment. The drafting team has combined the existing MOD-026-1 and MOD-027-1 standards into a single standard as part of Project 2020-06. The directive P143 associated with this project requires that the processes outlined in the standard be equivalent for both synchronous and inverter-based generation types. Because of this combination and the directive requirements, the team is unable to differentiate the Model Validation and Model Verification processes in a way that would make them more cost-effective for one generation type over the other. The comment is noted.

Adam Burlock - TransAlta Corporation - 5 - MRO,WECC,NPCC,RF

Answer	No
Document Name	

Comment

Inclusion of the Requirement R3 exemption for legacy facilities in Attachment 2 Row 14 is prudent and appropriate.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, the drafting team in previous iterations had included a legacy exemption. Based on comments submitted by the industry, the DT will be adding in Requirement R3 which includes legacy facility exemption with this posting.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company supports EEI comments.

Likes 0	
Dislikes 0	

Response

Please see the DT's response to EEI's comment.	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Nrextera supports comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	
Reclamation recommends that all IBR resource compliance standards have their own documents. Heavily modifying existing standards is causing confusion and undue effort to identify compliance requirement among non-IBR resource owning entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team (DT) has combined MOD-027-1 and MOD-026-1 into a single standard. FERC Order No. 901, Directive P143, requires that both types of generation undergo the same processes to achieve Model Validation and Model Verification.	

To fulfill this directive, the DT ensured that the combined standard applies equally to all generation types, without differentiating the Model Validation and Model Verification processes based on generation technology. However, to improve readability and reduce confusion, separate tables are provided in Attachment 1, organized by generation type.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No

Document Name	
Comment	
Xcel Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Steven Belle - Dominion - Dominion Virginia Power - 1,3, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports the EEI position.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
None	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
No alternatives other than those listed below	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Nick Leathers - Ameren - Ameren Services - 1,3,5,6 - MRO,SERC	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI’s comment.	

Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Producing validated EMT models is complex, time-consuming, and require vendor cooperation. It will also apply to the new MO projects. Especially challenging if vendor-provided models are proprietary, incomplete, or not aligned with system simulation requirements. The standard should account for exceptions for vendor models that cannot meet the requirements, such as some existing facilities may not have the monitoring infrastructure to capture event data, making validation difficult. Further there may be some OEM's no longer in business for new IBR sites thus making many of the requirements of the model nearly impossible to meet. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Based on feedback received, the drafting team (DT) will be adding an exemption for legacy facilities in Requirement R3.	
Danielle Moskop - Ameren - Ameren Services - 1,3,5,6 - MRO,SERC	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Please see the DT's response to EEI's comment.	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD and BANC agree with the comments submitted by Chelan County PUD (CCPUD) and First Energy. We believe there will be additional costs for registered entities with traditional/legacy units but we cannot determine if there is a more cost-effective option until the other question responses have been resolved.	
Likes 0	
Dislikes 0	
Response	
Please see the responses to CCPUD and FirstEnergy's comments. Thank you for the observation regarding the indeterminate nature of a more cost-effective option.	

As specified in Paragraph 143 of FERC Order No. 901, traditional generating units must follow the same process as non-traditional generating units to achieve Model Validation and Model Verification. This ensures consistency across generation types. In response to stakeholder feedback, the drafting team (DT) has added language to Requirement R3 that provides an exemption for legacy facilities from EMT-related requirements under certain conditions.	
Bob Cardle - Pacific Gas and Electric Company - 1,3,5 - WECC	
Answer	No
Document Name	
Comment	
Pacific Gas and Electric Corporation will not comment on cost-effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The Standard should account for exceptions for vendor models that cannot meet the requirements, such as existing facilities that may not have the monitoring infrastructure to capture event data, making validation difficult. Further there may be some OEMs no longer in business for new IBR sites thus making many of the requirements of the model nearly impossible to meet.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment. Based on this and other related feedback, the drafting team (DT) has added exemption language for legacy facilities under certain conditions in Requirement R3. This addition directly responds to concerns raised regarding applicability and cost-effectiveness for existing facilities.	
Kera Schwartz - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Chantal Mazza - Hydro-Quebec (HQ) - 1,5 - NPCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Isidoro Behar - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Scott Thompson - TXNM Energy - 1,3	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Matt Lewis - Lower Colorado River Authority - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Sing Tay - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Daniel Gacek - Exelon - 1,3, Group Name Exelon	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Alison MacKellar - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	
Producing validated EMT models is complex, time-consuming, and require vendor cooperation. It will also apply to the new MO projects. Especially challenging if vendor-provided models are proprietary, incomplete, or not aligned with system simulation requirements. The standard should account for exceptions for vendor models that cannot meet the requirements, such as some existing facilities may not have the monitoring infrastructure to capture event data, making validation difficult. Further there may be some OEM's no longer in business for new IBR sites thus making many of the requirements of the model nearly impossible to meet. Alison Mackellar on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to Kimberly Turco Constellation's comment.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
R1.1/R1.2. PRC-024/029 already governs the voltage and frequency trip settings. It seems unnecessary and duplicative for GOs and TOs to submit protection models for Under/Over Voltage and Under/Over Frequency when PRC-024/029 already requires ride through criteria to be met for units. Standalone recommendations for inverter-based resources (IBR), unregistered and aggregated IBR, and aggregated distributed energy resources should be created. Existing MOD-026 testing on large synchronous generators has taken time to confidently execute validation. The proposed changes disrupt the established process and will significantly increase resources to revise, plan, execute and review. GOs can use existing standards to demonstrate the same compliance. This change will also now require MOD-026 validation due to changes to previously unrelated PRC standards. Trip settings and limits are not typically bypassed during MOD-026 testing. This, combined with relying on existing PRC compliance demonstrations, should be used. Frequent changes, including temporary changes, are made to protection schemes previously outside of MOD-026. Will a MOD-026 verification and validation now be required for these changes?	
Likes 0	
Dislikes 0	
Response	

There is a difference between PRC-029-1 and MOD-026-1. PRC-029-1 specifies the minimum ride-through requirements for facilities, while MOD-026-1 focuses on modeling these protective functions to assess their dynamic behavior and impact during various operating conditions. FERC Order No. 901, Directive 141, also states: "dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs, including momentary cessation and/or tripping, and all ride-through behavior." The references to PRC-029 and PRC-024 are partly due to the directive assigned to the project and how the drafting team (DT) is fulfilling it.

Thank you for the suggestion.

Additional limiter functions have been added to the table so that the Transmission Planner (TP) and Planning Coordinator (PC) can specify which protective functions they want the Generator Owners (GOs) and Transmission Owners (TOs) to provide. The current Implementation Plan (IP) allows for a 10-year continuation if entities are already compliant with MOD-026-1 and MOD-027-1. This will cover GOs and TOs that have demonstrated compliance with the current standards.

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

Project 2020-06 and FERC Order 901 are addressing system instability and separation issues due to IBR generators. After reviewing FERC Order 901, BPA has identified no areas where High Voltage Direct Current (HVDC) or flexible alternating current transmission systems (FACTS) are referenced. BPA believes HVDC and FACTS does not fit the definition of an inverter-based resource (IBR) in the NERC Glossary of terms and is not a "resource", like generation. BPA believes HVDC transmits power and FACTS devices support transmission. Additionally, the Technical Rationale for Reliability Standard Project 2020-06 Verifications of Models and Data for Generators MOD-026-2 – Verification of Models and Data, dated May 2025, references *"Transmission Connected Dynamic Reactive Resources and HVDC Equipment – Assessment of Applicability in Reliability Standards NERC SAMS White Paper February 2019"* as one of the drivers behind including HVDC and FACTS to MOD-026. However, *"Transmission Connected Dynamic Reactive Resources and HVDC Equipment – Assessment of Applicability in Reliability Standards NERC SAMS White Paper February 2019"* states "LCC HVDC is not applicable to MOD-026".

BPA believes FACTS and HVDCs are extensively modeled in EMT software, studied, and tested (including fault testing) by the TO. BPA does not see the technical merits of including FACTS and HVDC in this scope of MOD-026-2. BPA recommends the DT remove HVCD and FACTS from the scope of the requirement revisions in MOD-026-2 as they have no precedence to cause the instability issues outlined in FERC Order 901.

For additional drafting team context:

Manufacturers often provide proprietary 'black box' models. BPA may not be able to verify some or all components of ‘black box’ models. BPA believes this would make Model Verification under the revised requirement impossible. It is common for vendors to include ‘black boxed’ portions of IBR, FACTS, or HVDC EMT models that contain proprietary information. ‘Black boxed’ models make the verification requirement impossible for GOs, TPs or TOs to complete. In general, the GO, TP, and TO trust the manufacturer to provide a Verified Model of the equipment they designed.

Likes 0	
Dislikes 0	

Response

The Drafting Team (DT) does not want to remove FACTS and LCC devices because they have a significant impact on the Bulk Power System (BPS). These devices have the potential to interact with other resources, and the DT sees a reliability need to include them, even if this goes beyond what the Order explicitly states.

The concept of "black boxing" is typically related to the control structure provided by the OEM; however, the configurable settings are accessible to the end user. The purpose of the model verification specified in the standard is to validate these configurable settings.

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	Yes
Document Name	

Comment

Similarly to the proposed revisions to MOD-032 under project 2022-02, this standard requires Transmission Owner(s) / Transmission Planner(s) to come up with (EMT) models and submit them for equipment that the respective TO/TP is not the owner of. We do not feel this is appropriate; that responsibility should lie with the BA or PC as they are in a better position to compel other entities to provide proper documentation.

Likes 0	
Dislikes 0	

Response

The Drafting Team (DT) is only requiring Transmission Owners (TOs) that own STATCOMs to develop EMT models for those devices. Only equipment owners—either Generator Owners (GOs) or TOs—are able to obtain EMT models from the OEMs. This is why MOD-026-2 requires them to provide these models to the Transmission Planner (TP) and Planning Coordinator (PC).

The TP and PC are responsible for developing the process that outlines what TOs and GOs must provide and follow in order to achieve model validation and model verification. The Balancing Authority (BA) is not an applicable entity for this project and is considered out of scope, as is the TP's role in developing EMT models.

Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6, Group Name Con Edison

Answer	Yes
Document Name	

Comment

Similarly to the proposed revisions to MOD-032 under project 2022-02, this standard requires Transmission Owner(s) / Transmission Planner(s) to come up with (EMT) models and submit them for equipment that the respective TO/TP is not the owner of. We do not feel this is appropriate; that responsibility should lie with the BA or PC as they are in a better position to compel other entities to provide proper documentation.

Likes 0	
Dislikes 0	

Response

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Erin Doane - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Similarly to the proposed revisions to MOD-032 under project 2022-02, this standard requires Transmission Owner(s) / Transmission Planner(s) to come up with (EMT) models and submit them for equipment that the respective TO/TP is not the owner of. We do not feel this is appropriate; that responsibility should lie with the BA or PC as they are in a better position to compel other entities to provide proper documentation.	
Likes 0	
Dislikes 0	
Response	
The Drafting Team (DT) is only requiring Transmission Owners (TOs) that own STATCOMs to develop EMT models for those devices. Only equipment owners—either Generator Owners (GOs) or TOs—are able to obtain EMT models from the OEMs. This is why MOD-026-2 requires them to provide these models to the Transmission Planner (TP) and Planning Coordinator (PC). The TP and PC are responsible for developing the process that outlines what TOs and GOs must provide and follow in order to achieve model validation and model verification. The Balancing Authority (BA) is not an applicable entity for this project and is considered out of scope, as is the TP's role in developing EMT models.	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Similarly to the proposed revisions to MOD-032 under project 2022-02, this standard requires Transmission Owner(s) / Transmission Planner(s) to come up with (EMT) models and submit them for equipment that the respective TO/TP is not the owner of. We do not feel this is appropriate; that responsibility should lie with the BA or PC as they are in a better position to compel other entities to provide proper documentation.	
Likes 0	
Dislikes 0	
Response	
The Drafting Team (DT) is only requiring Transmission Owners (TOs) that own STATCOMs to develop EMT models for those devices. Only equipment owners—either Generator Owners (GOs) or TOs—are able to obtain EMT models from the OEMs. This is why MOD-026-2 requires them to provide these models to the Transmission Planner (TP) and Planning Coordinator (PC). The TP and PC are responsible for developing the process that outlines what TOs and GOs must provide and follow in order to achieve model validation and model verification. The Balancing Authority (BA) is not an applicable entity for this project and is considered out of scope, as is the TP's role in developing EMT models.	
Timothy Singh - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP recommends separate standards for IBR/DER modeling. The current draft of Project 2020-06 combines numerous projects into one project. Addressing these projects separately and with a phased in implementation eases the burden on planning, budgeting, and labor costs.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the MOD-026-2 initial draft only has reference to registered IBRs and Synchronous generation. IBR DER is not included nor referenced in this draft. IBR DER is currently being covered in MOD-032-2 and MOD-033-3 drafts.	

The IP has a 10-year phase in plan to continue the current timeline for facilities that are MOD-026-1 and MOD-027-1 compliant currently. The regularly scheduled cycle would not change and give time for entities to prepare for the new standard once it is effective after the phase in period. The current IP also has a phased in approach for Requirements following the effective date of the standard, allowing 12 months for Requirement R1 and 36 months for Requirements R2 – R7.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	Yes
Document Name	
Comment	
While MOD-026-2 aims to improve model verification for inverter-based resources, the more cost-effective approach could involve leveraging existing disturbance monitoring data rather than requiring an additional validation process. Encourage standardized data-sharing among transmission planners and generator owners to reduce redundant verification efforts.	
Likes 0	
Dislikes 0	
Response	
The Model Validation process involves comparing model performance against measured data, which is sourced from either staged testing or disturbance measurements.	
Chris Wagner - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
A cost-savings that could be found is if there was a way to require OEMs to submit their UDM models for acceptance into the standard PSSE/PSLF libraries. This would theoretically eliminate the need to keep up with two different sets of models (generic/UDM) for each site in the positive sequence domain.	
Likes 0	

Dislikes 0	
Response	
Thank you for the suggestion, please review Project 2022-02 focusing on MOD-032. This topic is out of scope for this project.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
See Electric Reliability Council of Texas, Inc.'s (ERCOT's) response to Q5.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to ERCOT Q5 response.	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	Yes
Document Name	
Comment	
Comments: The original MOD-026-1 standard had a phased in approach for each Generator Owner (GO) over a 10 year period. The draft MOD-026-2 standard with its Implementation Plan has all Applicable Entities with facilities added to the standard having it become effective at the same time. Not only does this place a burden on the GOs and Transmission Owners (TO) but also on the Transmission Planners trying to either complete these reviews on their own or competing for limited consultant resources to perform the work by the required dates. A phased in approach would make becoming compliant with the standard much more cost effective.	
Likes 0	
Dislikes 0	

Response	
The MOD-026-2 Implementation Plan (IP) introduces a phased-in approach for the standard. Following the effective date of the standard, Requirement R1 will become effective after 12 months. Then, 24 months after the effective date of R1— 36 months from the effective date of the standard— Requirements R2 through R7 will take effect. In addition to this phased implementation, the IP preserves the existing 10-year model validation cycle. It clearly states that the new phased-in approach under MOD-026-2 will not impact the current cycle. Facilities or equipment that were model validated under MOD-026-1 will continue their 10-year cycle from the original validation date, ensuring continuity and consistency in compliance tracking.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	

Yes, the following alternatives are more cost-effective options to address the recommendations in FERC Order No. 901, and should be adopted in the next draft:

1. Most importantly, the entirety of the R3 requirement for the Generator Owner or Transmission Owner to provide and validate an EMT model should be removed from the draft standard. FERC's reasoning in Order 901 is inconsistent with R3's requirement for all IBRs in-service by the effective date of the standard, and potentially legacy IBRs, to provide EMT models, validate the plant's performance against the EMT model, and validate the EMT model against the positive sequence dynamic model required under R2. The R3 requirement departs from the solid reasoning FERC followed in Order 901, and also in Order 2023, in not imposing a universal requirement for IBRs to provide EMT models. In Order 2023, the Commission correctly weighed the cost and benefit of generators providing EMT models and validating them, and concluded that it would require "interconnection customers to submit EMT models with their interconnection requests only if the transmission provider performs an EMT study as part of its interconnection study process," as FERC notes in Order 901. FERC expanded on this reasoning by explaining why EMT models have limited value for addressing the reliability gaps it intended Order 901 to address. The full context of FERC's reasoning is provided in Paragraph 127 of Order 901:

"Many commenters request that the Commission consider requiring the inclusion of EMT models in the new or modified Reliability Standards. In Order No. 2023, the Commission required interconnection customers to submit EMT models with their interconnection requests only if the transmission provider performs an EMT study as part of its interconnection study process. We decline here, however, to direct NERC to require EMT models at this time because EMT models are typically used to examine the electromagnetic transient behavior of individual generation resources and to study plant-to-plant interactions. EMT models are not used to build interconnection-wide models or perform

respective studies and, as such, requiring their inclusion would not address the reliability gaps identified in section III above, which are the subject of the directives in this final rule. However, we note that NERC has existing and ongoing Reliability Standards projects that include EMT studies, and we encourage NERC and stakeholders to continue working in this area."

We agree with FERC that EMT models provide little to no value for efforts to build the larger-scale BPS models that are the focus of Order 901 and thus these MOD-026-2 revisions. If the drafting team believes that EMT models are needed to model IBR behavior during large signal disturbances, as is suggested by the comment in the Consideration of FERC Order 901 Directives document that "To address the IBR modelling behavior during large signal disturbances, EMT Model Verification requirement is added for IBRs with Requirement R3, Part 3.2," that need has already been addressed by other NERC Standards and by FERC Order 2023. Specifically, approved Standard PRC-028 requires comprehensive collection of high-resolution performance data from existing and new IBRs, and PRC-030 requires a comprehensive analysis of any unexpected deviations in IBR output. PRC-029, which NERC has submitted to FERC but has not yet been approved, also imposes a ride-through performance requirement on all IBRs, with limited exemptions that require legacy facilities with constrained capabilities to maximize their performance up to their capabilities. Together these three standards, as well as comparable ride-through performance and modeling requirements put into the *pro forma* interconnection agreement for newly interconnecting IBRs in FERC Order 2023, comprehensively address concerns that have arisen in the past regarding IBR performance during large signal events. As a result, there is no need to require EMT models as part of MOD-026-2, particularly given the cost of developing and validating an EMT model.

Developing and validating an EMT model is highly costly, time-consuming, and burdensome, and sharing EMT models among OEMs, Generator Owners, Transmission Planners, and Planning Coordinators also poses intellectual property and security concerns as they contain a detailed representation of equipment controls that reveals highly sensitive OEM design information. EMT models require detailed plant-specific inputs regarding equipment and settings, so assembling them is costly and time-consuming.

Generator owners and Planners do not have unlimited resources for complying with reliability requirements, and therefore Standards should prioritize devoting those scarce resources to efforts that most effectively and efficiently improve reliability. Given the limited reliability value of EMT models for the purposes of MOD-026-2 revisions to comply with Order 901, combined with the high cost of developing and validating an EMT model, and even potential reliability and security risks of sharing an EMT model, the MOD-026-2 draft does not properly balance these competing concerns in a way that cost-effectively advances grid reliability.

Due to the excessive cost of developing and validating EMT models, the MOD-026-2 draft could also be challenged at FERC for resulting in rates that are not just and reasonable, which is inconsistent with FERC's mandate under the Federal Power Act. The undue burden of requiring EMT models from IBRs but not synchronous generators is also potentially unduly discriminatory, which is also inconsistent with FERC's mandate under Section 205 of the Federal Power Act.

The draft's requirement for IBRs to provide EMT models also applies to Category 2 IBRs in the 20-75 MVA range, which is particularly burdensome for these smaller resources as the cost of developing and validating an EMT model likely does not decrease linearly, if at all, for smaller projects. As a result, the $/kW cost of providing an EMT model for smaller IBRs is likely to be very high, much higher than for large IBRs. Given this higher cost burden, requiring EMT models from these smaller resources further adds to the undue discrimination and potential for rates that are not just and reasonable that could result from the draft of MOD-026-2.

The best solution is for the drafting team to remove the R3 requirement in its entirety. In the alternative, NERC should embrace FERC's reasoning in Orders 901 and 2023 and adopt the requirement FERC imposed in Order 2023 to only require EMT models if the Transmission Planner and Planning Coordinator use generator EMT models to conduct an EMT study. This would allow Planners to require EMT models in cases where they do provide value for reliability, such as in areas with weak grid/short circuit strength issues where plant-to-plant interactions can affect reliability and EMT models must be used to tune plant controls to prevent harmful interactions among plants.

2. Section 1.2.1 of the MOD-026-2 draft gives the Transmission Planner and Planning Coordinator total discretion to "Identify which legacy facilities for which electromagnetic transient (EMT) model(s) are required under Requirement R3;". For many reasons, the cost and burden of developing and validating an EMT model is likely to be even greater for legacy IBRs than for new IBRs, providing further reason why the R3 requirement to develop and validate an EMT model should be removed in its entirety. First, most legacy IBRs are operated under fixed-price long-term Power Purchase Agreements, so there is no mechanism for the Generator Owner to recover the cost of EMT model development and validation. The cost of this retroactive requirement introduces costly uncertainty by creating risk that changing reliability requirements can add unanticipated costs, which will harm project finance and contracting steps that are necessary for the timely and cost effective addition of new resources to meet ongoing rapid load growth.

For EMT model development, for many legacy IBRs the OEM is no longer in business or no longer provides or prioritizes technical support for the legacy equipment, as was extensively documented in NERC's September 2024 workshop on PRC-029.{C}[1] Because developing an EMT model requires extensive proprietary information from the OEM, it may be difficult if not impossible for the Generator Owner to provide EMT models for many legacy IBRs.

EMT model validation is also challenging for legacy IBRs as in many cases laboratory tests are impractical if not impossible. Section 3.1 of the draft requires such a test, with footnote 6 explaining "A hardware specific test may include a factory type test, hardware in the loop test, or other manufacturer test to ensure the EMT model's large signal response emulates the supplied equipment to the extent possible." Section 3.1 does include the provision that "If test results are not obtainable, the Generator Owner or Transmission Owner shall document the reason," though it is not clear if that exemption can be readily obtained in all necessary cases, such as the case of an OEM that is still in business but does not prioritize support for the legacy model.

This highlights a fundamental problem of R3: the requirement is imposed on the Generator Owner with no binding requirement on the OEM, but the Generator Owner cannot comply without extensive cooperation from the OEM, which the OEM is under no obligation to provide. This concern is most pronounced for legacy IBRs, but can also apply to new IBRs as well.

The best solution to these concerns is for the R3 requirement to develop and validate an EMT model to be removed in its entirety for both new and legacy IBRs. In the alternative, the MOD-026-2 draft should be revised so that EMT models are not required for legacy IBRs.

3. Sections 3.4 and 3.5 require validation of EMT models against frequency and voltage disturbances through either performance during a real-world event or a staged test. However, a staged test of plant performance during large frequency or voltage disturbances can degrade plant equipment or impose maintenance or other costs on the plant. This is particularly true given the vastly expanded ride-through curves for IBRs proposed in PRC-029. A similar validation step is not required of synchronous generators in the MOD-026-2 draft, again indicating concerns about undue discrimination that could be raised at FERC. As above, the best solution to this concern is to remove the R3 requirement in its entirety.

4. Section 3.3 includes “auxiliary control devices” in the list of items that must be represented in an IBR EMT, with footnote 8 indicating that term is “Only to include those auxiliary control devices that act on voltage and/or frequency.” However, even this clarification fails to adequately delineate which devices are included in that requirement.

5. Requirement R4 requires an updated EMT model and positive sequence dynamic model “upon making a hardware, software, firmware, control mode, or setting change(s) to any in-service equipment specified in Requirement R2 or Requirement R3 that alters the applicable equipment’s dynamic response characteristic(s).” This list of changes is very expansive and vague, which is exacerbated by the vagueness of the term “alters,” and can introduce a very expensive requirement to provide a new positive sequence dynamic model and EMT model every time a routine update is made to hardware, software, firmware, control mode, or settings. The cost of this requirement will potentially harm reliability by dissuading Generator Owners from making helpful updates that improve reliability performance or security. Manufacturers and generator owners routinely update the firmware of operating projects for improved features and performance. Provided these improvements do not materially affect electrical performance, these changes should be allowed without the cost of re-submitting models, or this will risk delaying or disincentivizing helpful updates. The drafting team could address this concern by revising the requirement to clarify that new models are not required for change that do not materially alter electrical performance, potentially borrowing from brightline criteria that have been developed to define “material modification” in the context of changes to a generator interconnection application.

6. Attachment 2 rows 1-2 give the Generator Owner only 365 days to provide the model and validate it after the plant is identified or commissioned. In many cases Generator Owners will likely need more time, given the challenges with obtaining EMT models from OEMs discussed above, as well as the challenges in validation due to the infeasibility or undesirability of conducting staged tests, as also discussed above. As a result, this timeline should be significantly extended.

{C}[1] For the transcript of this event, see https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/Transcript%20-%20Day%201.pdf and https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/Transcript%20-%20Day%202.pdf

Likes 0	
Dislikes 0	

Response

1) The DT believes EMT modeling is necessary for BPS reliability, as demonstrated by several NERC disturbance reports.
Regarding the concern that EMT models pose intellectual property and security risks, OEMs have experience blackboxing their EMT models to protect their IP.

2) There are provisions in the standard for exempting certain legacy plants from providing EMT models.
In response to the comment that the requirement is imposed on the Generator Owner with no binding obligation on the OEM: OEMs are not NERC-registered entities.

3) R3 allows the option to validate performance using staged testing (within normal operating limits) or during a recorded system disturbance.

4) Given the wide variety of auxiliary control devices from different vintages of IBRs and from different OEMs, the DT determined it would be more effective to provide general guidance - "auxiliary control devices that act on voltage and/or frequency" - rather than attempt to enumerate the various control types.

5) If the proposed changes alter the dynamic performance, the DT believes these changes should be reflected in a new model to enable TPs and PCs to perform reliability studies using accurate and representative models. The GO are in best position to determine whether any proposed changes will alter the dynamic performance of their equipment.

6) The 365 days is a carry over from the previous standard and introduces no new burden to GOs.

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2, Group Name PJM, MISO, SPP, NYISO joint comments

Answer	Yes
Document Name	
Comment	
See response to Q5 for alternative considerations.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to Question 5.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ijad Dewan - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Joseph Scott - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Manish Patel - Silicon Ranch Corporation - 5 - SERC	
Answer	
Document Name	

Comment	
No comments regarding cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Josh Schumacher - Black Hills Corporation - 1,3,5,6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
David Vickers - Vistra Energy - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	
Document Name	
Comment	
Tri-State can not comment on cost-effective options at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Karina Valencia - Oncor Electric Delivery - NA - Not Applicable - Texas RE	
Answer	
Document Name	
Comment	
No vote – Abstain.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

Rhonda Jones - Invenergy LLC - 5,6	
Answer	
Document Name	
Comment	
Invenergy is unable to comment on the cost-effectiveness of the proposed draft standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	
Document Name	
Comment	
Invenergy is unable to comment on the cost-effectiveness of the proposed draft standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	

no comment

Likes 0	
Dislikes 0	

Response
Thank you for the comment.

Rob Robertson - Leeward Renewable Energy - 5

Answer	
Document Name	

Comment
Yes, the following alternatives are more cost-effective options to address the recommendations in FERC Order No. 901, and should be adopted in the next draft: **1.** Most importantly, the entirety of the R3 requirement for the Generator Owner or Transmission Owner to provide and validate an EMT model should be removed from the draft standard. FERC's reasoning in Order 901 is inconsistent with R3's requirement for all IBRs in-service by the effective date of the standard, and potentially legacy IBRs, to provide EMT models, validate the plant's performance against the EMT model, and validate the EMT model against the positive sequence dynamic model required under R2. The R3 requirement departs from the solid reasoning FERC followed in Order 901, and also in Order 2023, in not imposing a universal requirement for IBRs to provide EMT models. In Order 2023, the Commission correctly weighed the cost and benefit of generators providing EMT models and validating them, and concluded that it would require "interconnection customers to submit EMT models with their interconnection requests only if the transmission provider performs an EMT study as part of its interconnection study process," as FERC notes in Order 901. FERC expanded on this reasoning by explaining why EMT models have limited value for addressing the reliability gaps it intended Order 901 to address. The full context of FERC's reasoning is provided in Paragraph 127 of Order 901: *"Many commenters request that the Commission consider requiring the inclusion of EMT models in the new or modified Reliability Standards. In Order No. 2023, the Commission required interconnection customers to submit EMT models with their interconnection requests only if the*

transmission provider performs an EMT study as part of its interconnection study process. We decline here, however, to direct NERC to require EMT models at this time because EMT models are typically used to examine the electromagnetic transient behavior of individual generation resources and to study plant-to-plant interactions. EMT models are not used to build interconnection-wide models or perform respective studies and, as such, requiring their inclusion would not address the reliability gaps identified in section III above, which are the subject of the directives in this final rule. However, we note that NERC has existing and ongoing Reliability Standards projects that include EMT studies, and we encourage NERC and stakeholders to continue working in this area."

We agree with FERC that EMT models provide little to no value for efforts to build the larger-scale BPS models that are the focus of Order 901 and thus these MOD-026-2 revisions. If the drafting team believes that EMT models are needed to model IBR

behavior during large signal disturbances, as is suggested by the comment in the Consideration of FERC Order 901 Directives document that "To address the IBR modelling behavior during large signal disturbances, EMT Model Verification requirement is added for IBRs with Requirement R3, Part 3.2," that need has already been addressed by other NERC Standards and by FERC Order 2023. Specifically, approved Standard PRC-028 requires comprehensive collection of high-resolution performance data from existing and new IBRs, and PRC-030 requires a comprehensive analysis of any unexpected deviations in IBR output. PRC-029, which NERC has submitted to FERC but has not yet been approved, also imposes a ride-through performance requirement on all IBRs, with limited exemptions that require legacy facilities with constrained capabilities to maximize their performance up to their capabilities. Together these three standards, as well as comparable ride-through performance and modeling requirements put into the *pro forma* interconnection agreement for newly interconnecting IBRs in FERC Order 2023, comprehensively address concerns that have arisen in the past regarding IBR performance during large signal events. As a result, there is no need to require EMT models as part of MOD-026-2, particularly given the cost of developing and validating an EMT model.

Developing and validating an EMT model is highly costly, time-consuming, and burdensome, and sharing EMT models among OEMs, Generator Owners, Transmission Planners, and Planning Coordinators also poses intellectual property and security

concerns as they contain a detailed representation of equipment controls that reveals highly sensitive OEM design information. EMT models require detailed plant-specific inputs regarding equipment and settings, so assembling them is costly and time-consuming.

Generator owners and Planners do not have unlimited resources for complying with reliability requirements, and therefore Standards should prioritize devoting those scarce resources to efforts that most effectively and efficiently improve reliability. Given the limited reliability value of EMT models for the purposes of MOD-026-2 revisions to comply with Order 901, combined with the high cost of developing and validating an EMT model, and even potential reliability and security risks of sharing an EMT model, the MOD-026-2 draft does not properly balance these competing concerns in a way that cost-effectively advances grid reliability.

Due to the excessive cost of developing and validating EMT models, the MOD-026-2 draft could also be challenged at FERC for resulting in rates that are not just and reasonable, which is inconsistent with FERC's mandate under the Federal Power Act. The undue burden of requiring EMT models from IBRs but not synchronous generators is also potentially unduly discriminatory, which is also inconsistent with FERC's mandate under Section 205 of the Federal Power Act.

The draft's requirement for IBRs to provide EMT models also applies to Category 2 IBRs in the 20-75 MVA range, which is particularly burdensome for these smaller resources as

the cost of developing and validating an EMT model likely does not decrease linearly, if at all, for smaller projects. As a result, the $/kW cost of providing an EMT model for smaller IBRs is likely to be very high, much higher than for large IBRs. Given this higher cost burden, requiring EMT models from these smaller resources further adds to the undue discrimination and potential for rates that are not just and reasonable that could result from the draft of MOD-026-2.

The best solution is for the drafting team to remove the R3 requirement in its entirety. In the alternative, NERC should embrace FERC's reasoning in Orders 901 and 2023 and adopt the requirement FERC imposed in Order 2023 to only require EMT models if the Transmission Planner and Planning Coordinator use generator EMT models to conduct an EMT study. This would allow Planners to require EMT models in cases where they do provide value for reliability, such as in areas with weak grid/short circuit strength issues where plant-to-plant interactions can affect reliability and EMT models must be used to tune plant controls to prevent harmful interactions among plants.

2. Section 1.2.1 of the MOD-026-2 draft gives the Transmission Planner and Planning Coordinator total discretion to "Identify which legacy facilities for which electromagnetic transient (EMT) model(s) are required under Requirement R3;". For many reasons, the cost and burden of developing and validating an EMT model is likely to be even greater for legacy IBRs than for new IBRs, providing further reason why the R3 requirement to develop and validate an EMT model should be removed in its entirety. First, most legacy

IBRs are operated under fixed-price long-term Power Purchase Agreements, so there is no mechanism for the Generator Owner to recover the cost of EMT model development and validation. The cost of this retroactive requirement introduces costly uncertainty by creating risk that changing reliability requirements can add unanticipated costs, which will harm project finance and contracting steps that are necessary for the timely and cost effective addition of new resources to meet ongoing rapid load growth.

For EMT model development, for many legacy IBRs the OEM is no longer in business or no longer provides or prioritizes technical support for the legacy equipment, as was extensively documented in NERC's September 2024 workshop on PRC-029.1 Because developing an EMT model requires extensive proprietary information from the OEM, it may be difficult if not impossible for the Generator Owner to provide EMT models for many legacy IBRs.

1 For the transcript of this event, see https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/Transcript%20-%20Day%201.pdf and https://www.nerc.com/pa/Stand/202002_Transmissionconnected_Resources_DL/Transcript%20-%20Day%202.pdf

EMT model validation is also challenging for legacy IBRs as in many cases laboratory tests are impractical if not impossible. Section 3.1 of the draft requires such a test, with footnote 6 explaining "A hardware specific test may include a factory type test, hardware in the loop test, or other manufacturer test to ensure the EMT model's large signal response emulates the supplied equipment to the extent possible." Section 3.1 does

include the provision that "If test results are not obtainable, the Generator Owner or Transmission Owner shall document the reason," though it is not clear if that exemption can be readily obtained in all necessary cases, such as the case of an OEM that is still in business but does not prioritize support for the legacy model.

This highlights a fundamental problem of R3: the requirement is imposed on the Generator Owner with no binding requirement on the OEM, but the Generator Owner cannot comply without extensive cooperation from the OEM, which the OEM is under no obligation to provide. This concern is most pronounced for legacy IBRs, but can also apply to new IBRs as well.

The best solution to these concerns is for the R3 requirement to develop and validate an EMT model to be removed in its entirety for both new and legacy IBRs. In the alternative, the MOD-026-2 draft should be revised so that EMT models are not required for legacy IBRs.

3. Sections 3.4 and 3.5 require validation of EMT models against frequency and voltage disturbances through either performance during a real-world event or a staged test. However, a staged test of plant performance during large frequency or voltage disturbances can degrade plant equipment or impose maintenance or other costs on the plant. This is particularly true given the vastly expanded ride-through curves for IBRs proposed in PRC-029. A similar validation step is not required of synchronous generators in the MOD-026-2 draft, again indicating concerns about undue discrimination that could

be raised at FERC. As above, the best solution to this concern is to remove the R3 requirement in its entirety.

4. Section 3.3 includes "auxiliary control devices" in the list of items that must be represented in an IBR EMT, with footnote 8 indicating that term is "Only to include those auxiliary control devices that act on voltage and/or frequency." However, even this clarification fails to adequately delineate which devices are included in that requirement.

5. Requirement R4 requires an updated EMT model and positive sequence dynamic model "upon making a hardware, software, firmware, control mode, or setting change(s) to any in-service equipment specified in Requirement R2 or Requirement R3 that alters the applicable equipment's dynamic response characteristic(s)." This list of changes is very expansive and vague, which is exacerbated by the vagueness of the term "alters," and can introduce a very expensive requirement to provide a new positive sequence dynamic model and EMT model every

time a routine update is made to hardware, software, firmware, control mode, or settings. The cost of this requirement will potentially harm reliability by dissuading Generator Owners from making helpful updates that improve reliability performance or security. Manufacturers and generator owners routinely update the firmware of operating projects for improved features and performance. Provided these improvements do not materially affect electrical performance, these changes should be allowed without the cost of re-submitting models, or this will risk delaying or disincentivizing helpful updates. The drafting team could address this concern by revising the requirement to clarify that new models are not required for change that do not materially alter electrical performance, potentially borrowing from brightline criteria that have been developed to define “material modification” in the context of changes to a generator interconnection application. **6.** Attachment 2 rows 1-2 give the Generator Owner only 365 days to provide the model and validate it after the plant is identified or commissioned. In many cases Generator Owners will likely need more time, given the challenges with obtaining EMT models from OEMs discussed above, as well as the challenges in validation due to the infeasibility or undesirability of conducting staged tests, as also discussed above. As a result, this timeline should be significantly extended.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to Grid Strategies LLC comment.	

2. Do you agree that the proposed footnote term "verified models," modified from the previous accepted standard MOD-026-1, is clear and understandable? If you do not agree, or recommend further changes, please explain.

Amy Wilke - American Transmission Company, LLC – 1	
Answer	No
Document Name	
Comment	
ATC supports the comments of the MRO NERC Standards Review Forum	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO-NSRF's comment.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2, Group Name PJM, MISO, SPP, NYISO joint comments	
Answer	No
Document Name	
Comment	
No. Use the phrase "verified and validated" instead of "verified models" as shorthand to mean both. It is worth the extra word for clarity, especially with IEEE 2800 and NERC defined terms having specific meanings for each. See the joint response to Q5.	
Likes 0	
Dislikes 0	
Response	

The DT has removed the term “verified models” and reworded locations containing the term to instead require models and accompanying documentation that meet the applicable Requirement Parts. While this did add extra words, the DT thinks this provides more clarity to address SPP’s concern.

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

It is the opinion of ACES that the use of the term “verified model” is both confusing and ambiguous. The newly proposed terms “Model Verification” and “Model Validation” were specifically created to remove this ambiguity and confusion. Therefore, it is the opinion of ACES that if an entity is to be required to perform both a Model Verification process and a Model Validation process, then it should be explicitly stated within the Reliability Standard Requirements by using the defined terms. Therefore, we recommend the following changes:

R2. Each Generator Owner or Transmission Owner shall provide: documentation of Model Verification of a positive sequence dynamic model(s) with associated parameters, any information pertaining to changes to the model(s) or its parameters, and the Model Validation results to its Transmission Planner that:

R3. For facilities identified under the Applicability sections 4.2.3.2, 4.2.4, 4.2.5, and 4.2.6, each Generator Owner or Transmission Owner shall provide: documentation of EMT Model Verification with associated parameters and the Model Validation results to its Transmission Planner according to the requirements and processes developed by its Transmission Planner and Planning Coordinator in Requirement R1 Part 1.2, within the timeframe specified in Attachment 2. The documentation shall include at a minimum the following:

R4. Each Generator Owner or Transmission Owner, upon making a hardware, software, firmware, control mode, or setting change(s) to any in-service equipment specified in Requirement R2 or Requirement R3 that alters the applicable equipment’s dynamic response characteristic(s), shall provide its Transmission Planner with one of the following, within the timeframe described in Attachment 2:

- An updated model(s) in accordance with Requirement R2 and Requirement R3 reflecting applicable change(s) being made; or
- A plan to provide the model(s) and associated information in accordance with Requirement R2 or Requirement R3.

R6. Each Generator Owner or Transmission Owner, after receiving a notification of denial under Requirement R5 or a request from its applicable Transmission Planner for a model review due to identified model or accompanying information deficiencies, shall provide a written response to its applicable Transmission Planner within the timeframe in Attachment 2. The written response shall contain one of the following:

- An updated model and accompanying information in accordance with Requirement R2 and Requirement R3;
- A plan to submit the model and accompanying information in accordance with Requirement R2 and Requirement R3; or
- Resubmission of the current model and accompanying information in accordance with Requirement R2 and Requirement R3, with additional technical justification and supporting evidence to address the notification of denial or request for model review from the Transmission Planner.

ACES also recommends striking the word verified from the following Row Numbers of the table in Attachment 2 (as currently numbered in Draft 1): 1, 2, 3, 4, 6, 7, and 10.

Likes 0	
Dislikes 0	

Response

The DT has removed the term “verified models” and reworded locations containing the term to instead require models and accompanying documentation that meets the applicable Requirement Parts. This addresses ACES’s concern regarding the ambiguity and confusion of the term “verified model.” By directly referring to Requirement Parts, the DT has provided unambiguous direction for model providers. The DT has made conforming changes to Requirement R3 and R4. Requirment R4 now has a timeline incorporated into the requirement language. The DT has also made changes to Requirements R5 and R6 that reflect the changes and concerns brough up by ACES.

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

The term verified models being defined through a footnote and utilized in a lowercased format as a defined term is confusing to industry and could be misinterpreted through other standards. The intent and definition should be clear for the application of the term verified models, as

it was expressed this was verified and validated. It would be preferable to define this term or utilize both defined terms for Verified Model and Validated Model.	
Likes 0	
Dislikes 0	
Response	
The Drafting Team has removed the term "verified models" and reworded locations containing the term to instead require models and accompanying documentation that meets the applicable Requirement Parts. The DT thinks this creates clear, unambiguous expectations for model providers. The defined terms are utilized within the Requirement Parts to ensure the models and documentation provided have verification and validation activities performed prior to submission.	
James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The footnote term "verified model" is easy to confuse with the new term "Model Verification". A synonym such as "corroborated", "demonstrated" or "confirmed" would better illustrate that the intent of the footnote term is a model that has undergone both Model Verification and Model Validation. Similarly, the NAGF also supports EEI comments regarding validation and verification.	
Likes 0	
Dislikes 0	
Response	
The DT has removed the term "verified models" and reworded locations containing the term to instead require models and accompanying documentation that meets the applicable Requirement Parts. The drafting team feels a preceding word to represent a mode that is Model Verified and Model Validated would still be confusing.	
Bob Cardle - Pacific Gas and Electric Company - 1,3,5 - WECC	
Answer	No
Document Name	

Comment	
Pacific Gas and Electric Corporation supports the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to EEI's comment.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	
The need to define "verified model" in footnotes 4 and 5 implies that the use of the term in this context is not inherently clear and understandable. The SDT should consider replacing all uses of "verified model(s)" and "verified EMT model(s)" with "verified and validated model(s)" and "verified and validated EMT model(s)," respectively. If this change were to be made, footnotes 4 and 5 could then be deleted.	
Likes 0	
Dislikes 0	
Response	
The DT has removed the term "verified models" and reworded locations containing the term to instead require models and accompanying documentation that meets the applicable Requirement Parts. Thank you for the suggestions. The revisions made by the DT allowed for the removal of footnotes 4 and 5.	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	No
Document Name	
Comment	

Comments: The term ‘verified models’ while clarified in the footnote has the potential to cause confusion for both the GO/TO and the TP. Suggest the new Model Verification and Model Validation terms be used or a new term that does not include verified or validated be developed.	
Likes 0	
Dislikes 0	
Response	
The DT has removed the term “verified models” and reworded locations containing the term to instead require models and accompanying documentation that meet the applicable Requirement Parts. This allowed the DT to avoid creating a new term, as suggested.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	
The need to define “verified model” in footnotes 4 and 5 implies that the use of the term in this context is not inherently clear and understandable. The SDT should consider replacing all uses of “verified model(s)” and “verified EMT model(s)” with “verified and validated model(s)” and “verified and validated EMT model(s),” respectively. If this change were to be made, footnotes 4 and 5 could then be deleted.	
Likes 0	
Dislikes 0	
Response	
The DT has removed the term “verified models” and reworded locations containing the term to instead require models and accompanying documentation that meets the applicable Requirement Parts. Thank you for the suggestions. The revisions made by the DT allowed for the removal of footnotes 4 and 5.	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	

Comment	
MEC supports the comments of the MRO NERC Standards Review Forum	
Likes 0	
Dislikes 0	
Response	
Please see the drafting team's response to MRO NSRF's comment.	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
The term verified models being defined through a footnote and utilized in a lowercased format as a defined term is confusing to industry and could be misinterpreted through other standards. The intent and definition should be clear for the application of the term verified models, as it was expressed this was verified and validated. It would be preferable to define this term or utilize both defined terms for Verified Model and Validated Model.	
Likes 0	
Dislikes 0	
Response	
The DT has removed the term "verified models" and reworded locations containing the term to instead require models and accompanying documentation that meets the applicable Requirement Parts. The revisions made by the DT allowed for the defined terms to be referenced in the Requirement Parts and avoid the introduction of any new, confusing terms.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	

Comment	
NIPSCO agrees with EEI's suggestion of the following: * Each Transmission Planner and its Planning Coordinator shall jointly develop dynamic modeling requirements and processes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's response to EEI's comments.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
See ERCOT's response to Q5.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the response to Question 5.	
Daniel Gacek - Exelon - 1,3, Group Name Exelon	
Answer	No
Document Name	
Comment	
This could cause confusion with the new definitions.	

Exelon supports the clarification suggested in the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
The proposed footnote term "verified models" is not clear and appears to be a new definition that combines two definitions – Model Validation and Model Verification. SMUD and BANC agree with the comments provided by BC Hydro that would help clear up the term "verified models".	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to BC Hydro's comment.	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC EnergyGroup supports the comments of EEI.	
Likes 0	

Dislikes 0	
Response	
Please see the DT’s response to EEI’s comment.	
Danielle Moskop - Ameren - Ameren Services - 1,3,5,6 - MRO,SERC	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI’s comment.	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation concurs with NAGF comments Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	
Response	
Please see the DT's response to NAGF's comment.	
Nick Leathers - Ameren - Ameren Services - 1,3,5,6 - MRO,SERC	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	No
Document Name	
Comment	
The revised term "verified models" appears to improve clarity compared to MOD-032-1, but further refinement may be needed. The definition should explicitly state whether verification applies to steady-state, dynamic, or electromagnetic transient models to avoid ambiguity.	
Likes 0	
Dislikes 0	
Response	

The DT has replaced the term “verified model” with language that refers directly to the applicable Requirement Parts. In this way, the DT has made the relationship to both dynamic and electromagnetic transient models clear.	
Sing Tay - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
AES Indiana supports both MRO-NSRF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s responses to MRO NSRF and EEI’s comments.	
Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s responses to MRO NSRF and EEI’s comments.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No

Document Name	
Comment	
AZPS supports the following comment submitted by EEI on behalf of its members: Use of uncapitalized “model verification” could be confusing given the defined term. EEI suggests the following language: {C}o Each Transmission Planner and its Planning Coordinator shall jointly develop dynamic modeling requirements and processes. The requirements…	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI’s comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	No
Document Name	
Comment	
Tri-State supports MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to MRO NSRF’s comments.	
Steven Belle - Dominion - Dominion Virginia Power - 1,3, Group Name Dominion	
Answer	No
Document Name	

Comment	
Dominion Energy supports the EEI position.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC signed on to ACES comments. See ACES comments.	
Likes 0	

Dislikes 0	
Response	
Please see the DT's response to ACES's comment.	
Scott Thompson - TXNM Energy - 1,3	
Answer	No
Document Name	
Comment	
Create a NERC term for Verified Models, do not include definitions in footnotes.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments and suggestions. The DT has reworded locations containing the term "verified model" to instead require models and accompanying documentation that meets the applicable Requirement Parts. This makes the standard unambiguous and avoids the need to create more defined terms.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Use of uncapitalized "model verification" could be confusing given the defined term. EEI suggests the following: o Each Transmission Planner and its Planning Coordinator shall jointly develop dynamic model**ing** requirements and processes. The dynamic model requirements…	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment, the DT has taken this suggestion and elaborated upon this by specifying the requirements the model has undergone as to make sure there is clarity and no ambiguity.	
Timothy Singh - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
This should be capitalized to identify the defined term and to not cause confusion. Do not add this as foot note, as SRP recommends putting it in the NERC Glossary of Terms instead.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments and suggestions. The DT has reworded locations containing the term “verified model” to instead require models and accompanying documentation that meets the applicable Requirement Parts. This makes the standard unambiguous and avoids the need to create more defined terms.	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Please see the DT's response to EEI's comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy agrees with and suggests implementation of the following EEI comment regarding validation and verification:

Comments: Use of uncapitalized "model verification" could be confusing given the defined term. EEI suggests the following:

o Each Transmission Planner and its Planning Coordinator shall jointly develop dynamic modeling [delete] requirements and processes. The [delete] requirements…

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	

"verified model" and "verified EMT model" includes both Model Verification and Model Validation without further guidance or specificity on what this actually means. EMT has multiple definitions in the operating world and is confusing, and should be properly defined in this standard as Electro-magnetic transient ONLY applicable to IBR resources. Also, Model Verification and Model Validation definitions have not been added to the glossary of terms. The entire purpose of this standard has been changed from specific guidance for modeling of excitation to multiple confusing modeling requirements that are not properly delineated between IBR and non-IBR resources, with an unacceptable overall timeframe to meet the requirement.

Likes 0	
Dislikes 0	
Response	
Thank you for the comments and suggestions. The DT has reworded locations containing the term "verified model" to instead require models and accompanying documentation that meets the applicable Requirement Parts. This makes the standard unambiguous.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
We appreciate the drafting team's efforts to define a "verified model" and believe it is needed. With Model Verification being defined as the "process of confirming model structure and parameter values without simulation" there are several instances in the Standard and technical rationale where it appears model verification and verified model are being used interchangeably. This leads to confusion as to what exactly is bring asked. It would be beneficial for one of these terms "verified model" and "Model Verification" to use a different word other than verified/verification. Examples: Technical Rational says GO/TO are responsible for providing validated and verified models. With the Standard's footnote definition, a verified model includes validation so it is repetitive and leads to confusion as to why it is repeating itself. R1 states the TP & PC shall jointly develop dynamic model verification requirements and processes. "model verification" is a defined term and it is confusing if they are only developing processes for confirming model structure and parameter values without simulation. We believe the intent is to define the requirements and processes for "verified models". R1 1.4 uses Model Verification with capitalization. Is this a process only for providing the model parameters and settings that have been checked without simulation? It is unclear what is Model Verification is supposed to mean. M2 states the GO/TO have evidence it provided Model Verification (with capitals) but by definition "Model Verification" does not meet all R2 requirements. (does not include model simulation/validation)	

Suggest wording R2 and R3 the same way.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments and suggestions. The DT has reworded locations containing the term “verified model” to instead require models and accompanying documentation that meets the applicable Requirement Parts. This makes the standard unambiguous and clarifies the relationship between Model Verification and Model Validation.	
Isidoro Behar - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
The proposed footnote terms “verified model,” and “verified EMT model” (footnotes 4 and 5) are relatively clear and understandable. However, the proposed footnote terms “verified models,” and “verified EMT model” are used throughout the standard in various requirements. To avoid confusion and to allow for enhanced visibility of these terms, we would recommend that a formal definition be created for both of these terms. The definition of these footnote terms should correlate directly with the definitions for Model Verification and Model Validation.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments and suggestions. The DT has reworded locations containing the term “verified model” to instead require models and accompanying documentation that meets the applicable Requirement Parts. This makes the standard unambiguous and avoids the need to create more defined terms.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	
If NERC Glossary Terms are used in reliability standards, BPA recommends they be included in the requirement, not in a footnote. If actions are required by a Registered Entity, BPA believes the language should be explicit in the requirement language to avoid confusion, which will increase audit clarity and efficiency.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments and suggestions. The DT has reworded locations containing the term “verified model” to instead require models and accompanying documentation that meets the applicable Requirement Parts. This makes the standard unambiguous and avoids the need to create more defined terms.	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
No, USV does not agree with the proposed footnote term “verified models” as this may cause confusion between the terms Model Verification and Model Validation. USV recommends changing to this term to “verified and validated models”.	
Likes 0	
Dislikes 0	
Response	
The DT has reworded locations containing the term “verified model” to instead require models and accompanying documentation that meets the applicable Requirement Parts. This makes the standard unambiguous.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No

Document Name	
Comment	

The footnotes, when read alone, may be clear but the use of "Model Verification" and "Model Validation" mixed with "dynamic model verification," "verified models," and occasionally just "models" throughout the standard reduces overall clarity. Consider leaning on the newly defined capitalized terms.

“Verify” is used throughout the standard and appears to address both Model Verification and Model Validation activities, which are defined as new terms, and "verified model" is stated in R2 Footnote 4 as being the result of both Model Verification and Model Validation activities. This can create confusion. The language should be revised to explicitly call out when Model Verification versus Model Validation activities are being required, and clarity is needed as to whether a model that is being referred to in the standard is based solely on verification data or if it is understood to have been adjusted in response to validation activities.

Consider creating two additional new defined terms “Verified Model” and “Validated Model,” as these concepts are important enough to warrant being elevated to a Glossary Term to ensure clarity and industry consensus.

“Verified Model” could be defined as a model created through Model Verification activities, such as reviewing equipment or facility design and settings documentation, and “Validated Model” could be defined as a Verified Model that has been adjusted through Model Validation activities, which could include engineering judgement, calculations, software checks, comparison to test data, etc. Not all model structures and parameter values are already documented, so distinguishing the nature of the models being referred to in the standard requirements is necessary for compliance clarity.

Soliciting the assistance of a philosopher might also be helpful with respect to the development and use of these new terms and definitions.

Likes 0	
Dislikes 0	
Response	

The DT has reworded locations containing the term “verified model” to instead require models and accompanying documentation that meets the applicable Requirement Parts. This makes the standard unambiguous and avoids the need to create more defined terms.

Richard Vendetti - NextEra Energy - 5	
Answer	No

Document Name	
Comment	
Nrextera supports comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Chantal Mazza - Hydro-Quebec (HQ) - 1,5 - NPCC	
Answer	No
Document Name	
Comment	
In Note 4, it is stated that a "verified model" includes both verification and validation activities. However, this creates confusion, as it contradicts the newly defined terms "Model verification" and "Model validation." It is inconsistent to exclude the comparison between	

measurements and simulations from the definition of “Model verification,” while including it in the definition of a “Verified model.” Since both terms derive from the verb “to verify,” the noun and the past participle should convey the same meaning.

Proposed solution: Remove Note 4 and ensure consistent terminology throughout the document by replacing terms such as “verified model” with “verified and validated model”, “plan to verify the model” with “plan to verify and validated the model”, etc., where appropriate.

Also, in each column of Tables 1.1 and 1.2 of Attachment 1, replace the phrase “Model(s) representing the…” with “Model Verification of the…”. The current wording does not clearly distinguish between verification and validation processes. The proposed revision will improve clarity and alignment with the intent of the standard.

Likes 0	
Dislikes 0	

Response

The DT has reworded locations containing the term “verified model” to instead require models and accompanying documentation that meets the applicable Requirement Parts. This has been done consistently throughout the standard.

Kera Schwartz - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	No
Document Name	

Comment

No, Southern Indiana Gas and Electric d/b/a CenterPoint Energy Indiana South (SIGE) does not

agree that the proposed footnote term “verified models” is clear and understandable, but agrees

with EEI’s proposed definitions and comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment, please see the response to EEI’s comment.

Josh Schumacher - Black Hills Corporation - 1,3,5,6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI's suggestion of the following: • Each Transmission Planner and its Planning Coordinator shall jointly develop dynamic model**ing** requirements and processes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see the response to EEI's comment.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) agrees with EEI's proposed comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see the response to EEI's comment.	
Adam Burlock - TransAlta Corporation - 5 - MRO,WECC,NPCC,RF	
Answer	No
Document Name	
Comment	

While the proposed footnote term is clear in isolation, use of "dynamic model verification", "Model Verification", "Model Validation", "verified models", and "models" are used inconsistently throughout.

Requirement R1 specifies "shall jointly develop dynamic model verification requirements and processes." It does not use the proposed defined terms, nor the proposed footnote. In parts 1.4 and 1.5, it specifies "documentation of Model Verification", but no mention of Model Validation.

Requirement R2 specifies "documentation of Model Verification" and also uses the proposed footnote term "verified model(s)". It also uses "model".

Requirement R3 and its subparts specify "verfied EMT models", "Model Verification" and "Model Validation".

Requirement R4 only specifies "verified model(s)".

Requirement R5 only specifies "model(s)".

Requirement R6 only specifies "verified model".

Consistency in term usage would be useful to registered entities.

Likes 1	Sacramento Municipal Utility District, 1,3,4,5,6, Kelley Tim
Dislikes 0	

Response

The DT has reworded locations containing the term “verified model” to instead require models and accompanying documentation that meets the applicable Requirement Parts. This has been done consistently throughout the standard.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy supports EEI's comments which state:

• Use of uncapitalized “model verification” could be confusing given the defined term. EEI suggests the following: o Each Transmission Planner and its Planning Coordinator shall jointly develop dynamic model**ing** verification requirements and processes for **verifying dynamic models**. The dynamic model verification requirements…

Likes 0	
Dislikes 0	

Response
Please see the response to EEI’s comment.
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5 - WECC, Group Name BC Hydro

Answer	No
Document Name	

Comment
BC Hydro appreciates the drafting team’s efforts and the opportunity to review, and offers the following comments. The Footnote 4 (and 5) states that a “verified model” (“verified EMT model” for Footnote 5) includes both Model Verification and Model Validation (new proposed NERC Glossary Terms). This appears to be an additional Requirement as it is not supported by R1 in conjunction with the proposed Model Verification Glossary Term definition. Recommend revising the wording to match the intention of the new defined Glossary Terms, i.e. the Model Verification and Model Validation processes produce a “verified model” and a “validated model”, respectively. One way to achieve this can be by using the term “verified and validated model” when the requirement is to do both Model Verification and Model Validation, and reserve the term “verified model” for those instances where only Model Verification is required.

Likes 0	
Dislikes 0	

Response
Thank you for the comments and suggestions. The DT has reworded locations containing the term “verified model” to instead require models and accompanying documentation that meets the applicable Requirement Parts. This makes the standard unambiguous.

Manish Patel - Silicon Ranch Corporation - 5 - SERC	
Answer	No
Document Name	
Comment	
Per new definitions for Model Verification and Model Validation and given that MOD-026-2 address plant level model post-commissioning, the model at the end of Model Verification and Model Validation processes should be verified model and validated model respectively. However, FNs 4 and 5 mention that "verified model" includes both Model Verification and Model validation activities. This is very confusing. For a plant level model, after commissioning, it makes sense that "verified model" is an output of "Model Verification" process and "validated model" is an output of "Model Validation" process.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. The DT has reworded locations containing the term "verified model" to instead require models and accompanying documentation that meets the applicable Requirement Parts. This makes the standard unambiguous.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
The definition is clear and understandable. WECC suggests you consider adding it at a Golossary Term.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Alison MacKellar - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Chris Wagner - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Joseph Scott - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ijad Dewan - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment.	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Matt Lewis - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Erin Doane - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6, Group Name Con Edison	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Thomas Foltz - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
David Vickers - Vistra Energy - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Karina Valencia - Oncor Electric Delivery - NA - Not Applicable - Texas RE	
Answer	
Document Name	
Comment	
No vote – Abstain with provided comment: Can the SDT please clarify why “Model Validation” is not explicitly included in Requirements R1 and R2?	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the DT’s response to EEI’s comment.	

Greg Davis – Georgia Transmission Corporation Segment 1

Answer	No
Document Name	
Comment	
Comments: Model Verification: The process of confirming that model structure and parameter values represent the equipment or facility design and settings by reviewing equipment or facility design and settings documentation. This definition does not appear to add any value. If understood correctly, the applicable entity is to read model documentation to be sure that the model parameters match the parameters in the documentation. This seems like an unnecessary administrative box-checking exercise. Furthermore, by definition, validate and verify are synonymous. Therefore, having separate and conflicting NERC glossary definitions for the two terms cause much confusion.	
Likes 0	
Dislikes 0	
Response	
The DT has reworded locations containing the term "verified model" to instead require models and accompanying documentation that meets the applicable Requirement Parts. This has been done consistently throughout the standard.	

3. Do you agree that the proposed implementation plan represents a reasonable period to implement MOD-026-2 consistent with FERC's directives to implement all requirements by 2030? If you do not agree, or recommend further changes, please explain.	
Manish Patel - Silicon Ranch Corporation - 5 - SERC	
Answer	No
Document Name	
Comment	
The Implementation Plan should consider providing more time for non-BES IBRs to comply with the requirements of this standard. As written, legacy facilities meeting criteria for non-BES IBRs will be required to provide positive-sequence dynamic models and EMT models (when identified by TP) within 12 months of TP making Model Verification process available. This is an extremely short time to be able to gather data, develop models, verify and validate models (based on staged tests) etc.	
Likes 2	Avangrid Renewables, 5, Lauer Hannah; Sacramento Municipal Utility District, 1,3,4,5,6, Kelley Tim
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030.	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5 - WECC, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
The General Consideration section of the draft Implementation Plan states that "After the twelve (12) month implementation period, Requirements R2, R3, R4, R5, and R6 will have a twenty-four (24) month phased in period". However, the Effective Date and Phased-In Compliance Dates section indicates that R2, R3, R4, R5, and R6 will be enforceable 24 months after the effective date of the MOD-026-2 (or MOD-032-2). Please revise for consistency.	
Likes 0	
Dislikes 0	
Response	

The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. The DT will review the IP for consistency and ensure there is clarity.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Until concerns are resolved, FirstEnergy cannot support the Implementation Plan of this proposed standard	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the comment is noted.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name CHPD	
Answer	No
Document Name	
Comment	
Upon reviewing the May 2025 Implementation Plan, the dates specified in "Compliance Date for MOD-026-2 Requirements R2, R3, R4, R5, and R6" do not seem to align with the requirements specified in "Initial Performance Dates." Further clarification is needed.	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No.901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. The initial performance dates are for the current MOD-026-1 and MOD-027-1 that are currently in the 10 year cycle, these detail how to handle currently Model Valdiated and Model Verfiied facilities and equipment.	
Josh Schumacher - Black Hills Corporation - 1,3,5,6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	

Answer	No
Document Name	
Comment	
Black Hills Corporation feels that the Implementation Plan needs to provide more time for non-BES IBR's to comply with the requirements of this standard. As written, 12 months of Transmission Planning making Model Verification process available (which currently most have); thus the 12 months is too short for legacy IBR's to gather data and develop models to provide positive-sequence and EMT models.	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No.901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. The team also discussed that most TP's have 12 months for this and felt it would be doable with the limited timeline.	
Chantal Mazza - Hydro-Quebec (HQ) - 1,5 - NPCC	
Answer	No
Document Name	
Comment	
Add a provision to the Implementation Plan to address the scenario where a future revision of the Bulk Electric System (BES) definition introduces new applicability criteria. Proposed Addition: In the event of a change to the BES definition that results in new applicability criteria for existing units (e.g., criteria I2.a is change from 20 MVA to 10MVA for the Gross individual nameplate rating) , an implementation period of approximately two (2) years shall be granted for compliance with Requirements R2, R3, R4, R5, and R6 for the newly applicable facilities. Rationale: The current version of MOD-026-2 does not account for future changes to the BES definition. Without an explicit implementation period, newly applicable units would be immediately subject to compliance, which is operationally and logistically unfeasible.	
Likes 0	
Dislikes 0	
Response	

The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. The drafting team does take into account for the possible change to the BES definition with the facilties section 4.2.5 and 4.2.6 as these encompass beyond the BES and into the BPS which facilties need to be incoprated to ensure reliability.	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Nrextera supports comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
David Vickers - Vistra Energy - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Vistra supports comments made by Silicon Ranch Corp.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to Silicon Ranch Corp.	
Alison MacKellar - Constellation - 5,6	
Answer	No
Document Name	

Comment	
Constellation has a concern that implementing R2 within 24 months of effective date does not provide adequate time for large fleets as well as the preexisting 10 year validations required. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. The initial performance dates relate to the 10 year cycle already in progress, the timelines above relate to new cycles/when the standard is accepted going forward.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
MOD-026-1 has a 10-year requirement. Existing MOD-026-1 testing should be credited until the next validation is needed up to 10 years. The Milestone 3 project is modifying numerous standards and definitions and incorporating significant requirements for increased coordination and data collection. TVA recommends extending the implementation plan and coordinating effective dates with all other Milestone 3 projects.	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. The DT has the existing 10-year requirements in the Attachment 2, and the currently in cycle 10-year cycle from MOD-026-1 are detailed in the initial performance dates for how that cycle will continue.	
Carver Powers - Utility Services, Inc. - 4	
Answer	No

Document Name	
Comment	
USV believes that the timeframes proposed in the implementation plan are not sufficient for entities to conduct all required activities prior to the implementation date. Many small entities and legacy facilities will require third parties to complete much of the data gathering, model development, and model verification and validation. USV recommends an implementation date of 36 months rather than the proposed 24 months. This gives the entity 24 months from the time the TP is required to post the criteria.	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
With the current state of available, qualified, industry vendor and employee resources, BPA believes the requirement for EMT studies (R3) does not lend itself to this FERC-directed implementation plan timeline. BPA understands that certain TOs and GOs are currently understaffed, and under a hiring freeze, that will likely affect their ability to meet the stated deadline. BPA recommends extending the deadline, given the industry wide constraints such as EMT modeling personnel, which would result in growing potential non-compliance issues.	
Likes 0	
Dislikes 0	
Response	
Requirement R3 EMT is not directly stated in the Order No. 901 but the DT believes it is needed to fulfill the full Model Valdiation and ensure reliability. It also helps fulfill directive to ensure that Model Valdiation is completed for all energy sources.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No

Document Name	
Comment	
MH recommends R3 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 a long time to train personnel and develop EMT models. Developing the EMT models for all the applicable in-service devices could be very challenging due to a lack of resources and lack of equipment manufacturer(s) support. This significant compliance cost issue of developing EMT models of these applicable in-service devices could be managed by leaving it to upon request of any of these applicable in-service devices by the TP/PC (based on their experience and study's needs).	
Likes 0	
Dislikes 0	
Response	
The DT has removed language out of Requirment R3 that should help address your concern.The DT does believe for reliability purposes that these entities do need to be included in the standard as they are interconnected to the BPC and do have an effect in conjuncation with IBR's to the BPS. For reliability reasons the DT will not fully remove these facilties out of the Relaibility Standard.	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	
Reclamation does not agree that this is a sufficient timeline to implement and successfully meet the directive (see question 2 above).	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No

Document Name	
Comment	

Due to numerous units that require testing and the competition for resources, we suggest changing the Implementation Plan for MOD-026-2 R2-R6 to read as follows:

Compliance Date for MOD-026-2 - R2, R3, R4, R5, and R6

Entities shall not be required to comply with Requirements R2, R3, R4, R5, and R6 until the later of: 1) [delete] forty-eight (48) months after the effective date of Reliability Standard MOD-026-2; or 2) [delete] forty-eight (48) months after the effective date of MOD-032-2.

Likes 0	
Dislikes 0	
Response	

The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. 48 months is too long and would violate the Order 901 timeline mandate.

Timothy Singh - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	

Obtaining and implementing a plan of action for older legacy units will take significant time to complete. Additionally adding new staff, building in house knowledge and capability to perform studies will take time. A phased in approach will help entities with the expensive alterations to budgeting, planning, and needed employment resources need to comply with FERC Order 901.

Likes 0	
Dislikes 0	
Response	

The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. The DT has a current phase in approach for requirements, but not on what’s defined as a legacy facility by the standard. The phased in approach is to give ample time to be able to preform these measures needed to implement the new MOD-026-2.

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
Additional facilities will meet applicability requirements (due to lower MVA & kV). Also, due to new requirements, utilities will need to add resources and provide training to adjust to all these changes. 5 yrs timeframe could be challenging to implement.	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. The five-year timeline would be too long and not meet the Order 901's effective date timeline.	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power noted an inconsistency in the description of the MOD-026-2 R2-R6 phased implementation dates. Specifically, the bottom paragraph on page 1 of the implementation plan states this: "An additional consideration the team noted is the requirement for all directives issued in FERC Order No. 901 to be fully implemented by January 1, 2030, including those covered by these standard revisions. After the twelve (12) month implementation period, Requirements R2, R3, R4, R5, and R6 will have a twenty-four (24) month phased in period to ensure all the requirements satisfying the directives are completely effective before the 2030 deadline set by FERC Order No. 901." While page 2 of the implementation plan says this: "Entities shall not be required to comply with Requirements R2, R3, R4, R5, and R6 until the later of: 1) twenty-four (24) months after the effective date of Reliability Standard MOD-026-2; or 2) twenty-four (24) months after the effective date of MOD-032-2."	

The difference in language between page 1 and page 2 may lead to confusion as to when the clock starts for the phased implementation. Tacoma Power recommends modifying the paragraph on page 1 to state “After the effective date of Reliability Standard MOD-026-2 or MOD-032-2 (whichever is later), Requirements R2, R3, R4, R5, and R6 will have a twenty-four (24) month phased implementation period to ensure all the requirements…” Tacoma Power also recommends including a timeline graphic in the implementation plan to show the various phased implementation milestones, so it’s easier to visualize the time allotted for the phased implementation (e.g. t0 + 12 months for effective date of MOD-026-2, t0+24 months for R1, t0+36 months for R2-R6, etc.).	
Likes 1	Sacramento Municipal Utility District, 1,3,4,5,6, Kelley Tim
Dislikes 0	
Response	
Thank you for the comment. The DT will revise this language to make sure to ensure there is clarity within the IP for MOD-026-2.	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	No
Document Name	
Comment	
Tri-State supports MRO NSRF comments.	
Likes 1	Nebraska Public Power District, 5, Bender Ronald
Dislikes 0	
Response	
Please see the DT’s response to MRO NSRF’s comment.	
Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF's comment.	
Karina Valencia - Oncor Electric Delivery - NA - Not Applicable - Texas RE	
Answer	No
Document Name	
Comment	
Oncor does not agree that the proposed implementation plan is a reasonable period to implement MOD-026-2. In the previous implementation plan draft, the SDT recognized the challenges that the modified standard presents to impacted entities and provided a three-year implementation plan. The same challenges exist, and the previous implementation period also satisfied the 2030 requirement, so why reduce the implementation period by one year? It is unnecessarily burdensome to impacted entities.	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. The DT will give entites as much time as possible in the IP.	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation has a concern that implementing R2 within 24 months of effective date does not provide adequate time for large fleets as well as the preexisting 10 year validations required. Kimberly Turco on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. The DT has in the initial performance dates about the already in progress 10-year cycle Model Valdiation process and how the new standard would not inturpt the current cycles. Please read Initial performance dates in the IP in regards to your question.	
Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD and BANC agree with the comments submitted by Tacoma Power and Oncor Electric Delivery. A graphic would help entities better understand the phased implementation milestones and more implementation time is needed due to the complexities and inexperience with dynamic IBR models.	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. Please see the response and the updated IP language.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
NIPSCO cannot support the Implementation Plan of this proposed standard until concerns are resolved.	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
There are other time constraints involved with entities who perform studies. Stakeholder processes may drive additional time periods to allow flexibility for updating existing agreements or developing those agreements for roles and responsibilities. At a minimum, WAPA recommends 18 months for implementation given the conforming changes required from the MOD-032 and TPL-008 changes proposed within a similar timeframe.	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. The DT is following a very similar timeline to the new MOD-032-2 standard. The DT feels to meet the directives the current dates approach will allow enough time yet still ensure relaibilty.	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
MEC supports the comments of the MRO NERC Standards Review Forum	
Likes 0	
Dislikes 0	
Response	

Please see the DT's response to MRO NERC forum's comment.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	
No, the drafting team should consider allowing 36 months, an additional year beyond the drafted Implementation Plan, for all entities to comply with Requirements R2, R3, R4, R5, and R6, or at the very least an additional year should be granted to non-BES entities.	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. Please see the updated IP language.	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	No
Document Name	
Comment	
Comments: The original implementation plan provided a phased approach for generation so that not only Generator Owners but also Transmission Planners were not overwhelmed with the work required of MOD-026-1 needing to all be completed at the same time. The implementation Plan proposed for MOD-026-2 leaves the existing staggered Implementation for the synchronous generators applicable under MOD-026-1 but has the remaining facilities all applicable on the same date. This means that all new Category 2 GOs, all new Category 1 GO-IBRs, and all of the other types of facilities will be competing for resources to both complete their reviews and have their TPs perform the required evaluations. Recommend a staggered approach similar to that identified for MOD-026-1 be included in the Implementation Plan for MOD-026-2.	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment. The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. Please see the updated IP language.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	No
Document Name	
Comment	
No, the SDT should consider allowing 36 months, an additional year beyond the drafted Implementation Plan, for all entities to comply with Requirements R2, R3, R4, R5, and R6, or at the very least an additional year should be granted to non-BES entities.	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	
No, the Implementation Plan leverages the MOD-032 Implementation Plan. The MOD-032 IP has a twenty-four plus month timeframe for the Standard with an additional phased in 12 month period for the data requirements under Requirement R2, R3, and R4. MOD-026 would be 12 or 24 months (Requirement R2 through Requirement R6) after approval. Basically, the DTs have built the IPs to force FERC to Approve MOD-032 and MOD-026 before the end of 2025 to meet 2030 for MOD-026 to be implemented by 2030. Having a “process” does not equate to actually implementing the process and mitigating this risk.	
Likes 0	
Dislikes 0	
Response	

The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. Please see the updated IP language. MOD-032 has been removed out of the MOD-026-2 IP as MOD-032 reference is not in MOD-026-2 standard now.	
James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Implementing R2 within 24 months of effective date does not provide adequate time for large fleets as well as the preexisting 10-year validations required. Due to numerous units that require testing and the competition for resources, we suggest changing the Implementation Plan for MOD-026-2 R2-R6 to read as follows: Compliance Date for MOD-026-2 - R2, R3, R4, R5, and R6 Entities shall not be required to comply with Requirements R2, R3, R4, R5, and R6 until the later of: 1) [twenty-four (24)] forty-eight (48) months after the effective date of Reliability Standard MOD-026-2; or 2) [twenty-four (24)] forty-eight (48) months after the effective date of MOD-032-2.	
Likes 0	
Dislikes 0	
Response	
The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. Please see the updated IP language. 48 months would be not be fesiable with the current Order 901 timeline to meet the 2030 deadline, and also for reliability.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

There are other time constraints involved with entities who perform studies. Stakeholder processes may drive additional time periods to allow flexibility for updating existing agreements or developing those agreements for roles and responsibilities. At a minimum, MRO NSRF recommends 18 months for implementation given the conforming changes required from the MOD-032 and TPL-008 changes proposed within a similar timeframe.

Likes 0	
Dislikes 0	

Response

The timeline is as long as possible in order to fulfill FERC Order No. 901 directives P226. This directive orders the DT have the Relaibility Standard be fully effective by 2030. Please see the updated IP language. The DT has removed references of MOD-032 from the standard but MoD-032 does reference MOD-026. With that new reference it has to be the earlier of the two. The DT has updated language in the IP to help with comments received on the timeline.

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2, Group Name PJM, MISO, SPP, NYISO joint comments

Answer	No
Document Name	

Comment

Contrary to the assertions in the implementation plan, it is not clear that MOD-032-2 must be implemented before MOD-026-2. It seems that MOD-026-2 could still be an effective standard even if its references pointed to MOD-032-1 instead of MOD-032-2. MOD-026-2 currently refers to a generalized “MOD-032,” which presumably means the currently enforceable version of MOD-032 (regardless of whether that happens to be MOD-032-1 or MOD-032-2). The implementation plan seems to recognize this as well, noting that “the current MOD-032-1 already specifies the type of data needed” for MOD-026-2.

We also recommend the implementation plan be extended to 18 months in consideration of the planning processes that will be impacted and require stakeholder agreement for modification simultaneously with changes required from other recent and pending revisions such as MOD-032 and TPL-008. To the extent practical, aligning these MOD-032 and MOD-026 would be preferred.

Likes 0	
Dislikes 0	

Response

With revisions to the latest draft, MOD-026-2 must be implemented before MOD-032-2 now. The MOD-032-2 reference within MOD-026-2 has been removed, but a reference into MOD-032 referencing MOD-026 has been added. This reference requires MOD-26-2 to implemented before MOD-032 is, hence the wording “earlier” has been added to the IP.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC supports the comments of the MRO NERC Standards Review Forum	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to MRO NSRF’s comment.	
Adam Burlock - TransAlta Corporation - 5 - MRO,WECC,NPCC,RF	
Answer	Yes
Document Name	
Comment	
TransAlta is supportive of the initial performance dates for R2 and R3, based upon the periodic timeframes of their last performance under the respective requirements in MOD-026-1 and MOD-027-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Thomas Foltz - AEP - 3,5,6	
Answer	Yes

Document Name	
Comment	

While AEP has no objections to the Implementation Plan itself, we believe its documentation becomes very confusing starting with “when the periodic timeframe falls between” and continuing through the remainder of page 4. We believe the intention is to ensure that a GO’s compliance schedule in place under the version 1 standard is not somehow disrupted in the transition to version 2. That being said, much of page 4 could be re-written to greatly improve its clarity. We believe this section might benefit by breaking it into separate sections, perhaps for existing and planned projects. Diagrams, illustrations, or charts might prove useful as well. Additional clarity and improved readability would both ensure that all entities will read, understand, and follow the Implementation Plan correctly and that it will be applied consistently.

Further clarity is also needed when determining the periodic timeframes from the last model verification under the requirements of MOD-026-1 R2 and MOD-027-1 Requirement R2, respectively. Specifically, how should the applicable entity determine the correct initial performance date deadline to ensure compliance of MOD-026-2 Requirement R2 such that it is within 10 years of the most recent transmittal, when the same applicable unit has different latest model verification transmittal dates between MOD-026-1 and MOD-027-1? As an example, Unit A MOD-026-1 latest verification transmittal occurred in November 2016 and that same Unit A MOD-027-1 latest verification transmittal occurred in May 2023.

Our negative vote on the Implementation Plan is driven only by the lack of clarity that we believe is needed.

Likes 0	
Dislikes 0	
Response	

Thank you for the comment. The IP has re-reviewed and ensured that clarity was added that there will be a 36-month total phase in period for all requirements after the effective date taking place immediately. This will ensure that no gaps are present with the impelementation. The 10-year cycle is to ensure that current in-motion Model Validation cycles will not be disturbed, but as soon as the new effective standard is in place then one must comply with MOD-026-2.

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6

Answer	Yes
Document Name	
Comment	

See comments submitted by Edison Electric Institute

Likes 0	

Dislikes 0	
Response	
Please see the DT’s response to EEI’s comment.	
Scott Thompson - TXNM Energy - 1,3	
Answer	Yes
Document Name	
Comment	
Seems quite a few of these new standards are dependent of another standard for implemntation, if that is the case, why the two standards, instead of just one.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI’s comment.	
Steven Belle - Dominion - Dominion Virginia Power - 1,3, Group Name Dominion	
Answer	Yes

Document Name	
Comment	
Dominion Energy supports the EEI position.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	Yes
Document Name	
Comment	
The revised term "verified models" appears to improve clarity compared to MOD-032-1 but further refinement may be needed. The definition should explicitly state whether verification applies to steady-state, dynamic, or electromagnetic transient models to avoid ambiguity.	
Likes 0	

Dislikes 0	
Response	
The term “verified model” has been removed from the updated MOD-026-2 draft based on comments received. Clarity has been added to MOD-026-2 with the removal of this term.	
Nick Leathers - Ameren - Ameren Services - 1,3,5,6 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI’s comment.	
Danielle Moskop - Ameren - Ameren Services - 1,3,5,6 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI’s comment.	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	

Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Contrary to the assertions in the implementation plan, it is not clear that MOD-032-2 must be implemented before MOD-026-2. It seems that MOD-026-2 could still be an effective standard even if its MOD-032 references pointed to MOD-032-1 instead of MOD-032-2. MOD-026-2 currently refers to a generalized "MOD-032," which presumably means the currently enforceable version of MOD-032 (regardless of whether that happens to be MOD-032-1 or MOD-032-2). The implementation plan seems to recognize this as well, noting that "the current MOD-032-1 already specifies the type of data needed" for MOD-026-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. With the new revisions to MOD-026-2 and MOD-032-2, MOD-026-2 must be implemented before MOD-032-2 which is now reflected in the IP. This comment will be addressed with the updated language.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Kera Schwartz - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for the support.	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6, Group Name Con Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Erin Doane - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the support.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Matt Lewis - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Sing Tay - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Ijad Dewan - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Joseph Scott - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	

Chris Wagner - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Daniel Gacek - Exelon - 1,3, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for the support.	
Bob Cardle - Pacific Gas and Electric Company - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	
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	
Thank you for the support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Thank you for the support.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE noticed the retirement date for MOD-26-1 is “immediately prior” to the effective date of the standard. The initial performance and compliance dates, however, are 12 or 24 months after the effective date of the standard depending upon the particular requirement at issue. Is it the Standard Drafting Team’s intent to leave a potential gap between the retirement of the legacy MOD-026-1 requirements and the new MOD-026-2 requirements?

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The DT will revise the wording to ensure no GAP is present.

Wade Kiess - Platte River Power Authority - 3

Answer	
Document Name	

Comment

We support BC Hydro’s comment: “The General Consideration section of the draft Implementation Plan states that “After the twelve (12) month implementation period, Requirements R2, R3, R4, R5, and R6 will have a twenty-four (24) month phased in period”. However, the Effective Date and Phased-In Compliance Dates section indicates that R2, R3, R4, R5, and R6 will be enforceable 24 months after the effective date of the MOD-026-2 (or MOD-032-2). Please revise for consistency.”

Likes 0	

Dislikes 0	

Response
Thank you for the comment. MOD-032 has been removed from the MOD-026 standard, but MOD-032 references MOD-026-2 now. With that new reference MOD-026 must be implemented before MOD-032.

4. Do you agree that the proposed MOD-026-2 draft, together with MOD-033-3 draft, fulfills the FERC Order No. 901 Milestone 3 directive in P85. “to require Bulk Power System planners and operators to validate registered IBR models using disturbance monitoring data from installed registered IBR generator owners’ disturbance monitoring equipment”? If you do not agree or believe there is a gap in fulfilling this directive, or recommend further changes, please explain.

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	
Row 14 of Attachment 2 allows any legacy entity to disregard any Model Validation efforts and should be removed from the Standard. Getting a non-responsive Standard to pass using this option is not something the industry should consider.	
Likes 0	
Dislikes 0	
Response	
Row 14 has been moved into Requirement R3 as it is an exemption and should be included in the requirement language.	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation has concerns on clarifications of which IBR facilities will be required to complete modeling and that a clarification should be made in the standard. Further, this requirement is expanding scope to smaller facilities than previously required for IBR's Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
In the Facility section, Requirement 4.2.7 has been removed to clarify which entities and equipment are applicable to MOD-026-2, as well as to the Model Validation and Model Verification Requirements.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	No
Document Name	
Comment	
While the MOD-026-2 and MOD-033-3 improve the framework for model verification and validation, they fall short of the explicit FERC directive in Milestone 3. The Standards should clarify how transmission planners will access and utilize the disturbance data from generator owners. Add language for planners/operators to validate IBR models using measured disturbance data from Disturbance Monitoring Equipment (DME) installed at IBR.	
Likes 0	
Dislikes 0	
Response	
Thank you for the feedback on how a GAP is present in MOD-033-3 and MOD-026-2 when Planners such as the TP are utilizing DME data to perform Model Validation. This is outside the scope of MOD-026-2.	
Timothy Singh - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
While the proposed MOD-026-2 combines many directives included in FERC Order 901, it also creates undue strain on utilities to meet these deadlines while maintaining existing compliance standards. These directives would be less burdensome to implement if addressed in a singular manner.	
Likes 0	
Dislikes 0	
Response	

Thank you for the feedback regarding the burden and strain this standard places on utilities to meet deadlines, and how these challenges are addressed in a singular manner. In response to FERC Order No. 901 and the need to enhance Model Verification and Model Validation processes, MOD-027-1 and MOD-026-1 have been consolidated into a single standard. This consolidation, along with the directives in the FERC Order, is intended to improve reliability across the Bulk Power System (BPS), particularly through the inclusion of Inverter-Based Resource (IBR) Model Validation and Model Verification.

Paragraph 143 of Order No. 901 specifically directs NERC to establish a consistent process for Model Validation and Model Verification that does not depend on generation type.

Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	

Similarly to the proposed revisions to MOD-032 under project 2022-02, this standard requires Transmission Owner(s) / Transmission Planner(s) to come up with (EMT) models and submit them for equipment that the respective TO/TP is not the owner of. We do not feel this is appropriate; that responsibility should lie with the BA or PC as they are in a better position to compel other entities to provide proper documentation.

Likes 0	
Dislikes 0	
Response	

The TP and PC provide the process that the GO and TO must follow. The EMT models will be provided by the GO and TO, as they are the ones with contractual relationships with the OEMs.

Erin Doane - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	

Similarly to the proposed revisions to MOD-032 under project 2022-02, this standard requires Transmission Owner(s) / Transmission Planner(s) to come up with (EMT) models and submit them for equipment that the respective TO/TP is not the owner of. We do not feel this is appropriate; that responsibility should lie with the BA or PC as they are in a better position to compel other entities to provide proper documentation.	
Likes 0	
Dislikes 0	
Response	
The TP and PC provide the process that the GO and TO must follow. The EMT models will be provided by the GO and TO, as they are the ones with contractual relationships with the OEMs.	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	No
Document Name	
Comment	
Reclamation does not own any IBR resources, and strongly suggests that inclusion of IBR resources into MOD-026-2 be reconsidered into their own standard. Disturbance monitoring is in PRC-002 and should effectively remain there.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The MOD-026-2 standard needs to have equal processes that are not dependent on energy generation types. This process must be the same for synchronous generation as it is for non-synchronous generation as directed by FERC in directive P143. Disturbance monitoring data for synchronous generation is in PRC-002, but for IBR it is in PRC-028. The DT agrees that those are the respective standards for specifying the data collected and proper entities responsible for the data, and not in MOD-026-2.	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6, Group Name Con Edison	
Answer	No
Document Name	
Comment	

Similarly to the proposed revisions to MOD-032 under project 2022-02, this standard requires Transmission Owner(s) / Transmission Planner(s) to come up with (EMT) models and submit them for equipment that the respective TO/TP is not the owner of. We do not feel this is appropriate; that responsibility should lie with the BA or PC as they are in a better position to compel other entities to provide proper documentation.	
Likes 0	
Dislikes 0	
Response	
The TP and PC provide the process that the GO and TO must follow. The EMT models will be provided by the GO and TO, as they are the ones with contractual relationships with the OEMs.	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
Similarly to the proposed revisions to MOD-032 under project 2022-02, this standard requires Transmission Owner(s) / Transmission Planner(s) to come up with (EMT) models and submit them for equipment that the respective TO/TP is not the owner of. We do not feel this is appropriate; that responsibility should lie with the BA or PC as they are in a better position to compel other entities to provide proper documentation.	
Likes 0	
Dislikes 0	
Response	
The TP and PC provide the process that the GO and TO must follow. The EMT models will be provided by the GO and TO, as they are the ones with contractual relationships with the OEMs.	
Alison MacKellar - Constellation - 5,6	
Answer	No
Document Name	
Comment	

Constellation has concerns on clarifications of which IBR facilities will be required to complete modeling and that a clarification should be made in the standard. Further, this requirement is expanding scope to smaller facilities than previously required for IBR's Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
In the Facility section, 4.2.7 has been removed to add clarity on which entities and equipment are applicable to MOD-026-2 and the Model Validation and Model Verification Requirements. In reference to the comment, this requirement is expanding the scope to smaller facilities than previously required IBRs.	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Nrextera supports comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Chantal Mazza - Hydro-Quebec (HQ) - 1,5 - NPCC	
Answer	No
Document Name	
Comment	

We disagree with the current approach, as the integration of the IBR model Verification and Validation process has significantly altered the requirements for synchronous machines compared to those specified in MOD-026-1 and MOD-027-1. Please refer to the comments in Section 5 below for further details.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, and please see the DT's response to HQ question 5.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name CHPD	
Answer	No
Document Name	
Comment	
Model validation using disturbance monitoring equipment is not required under the current MOD-026/027. Distributed energy resource (DER) sites are not required to have disturbance monitoring equipment and is beyond the scope of MOD-026's changes. This is instead addressed under PRC-002 with different disturbance monitoring equipment applicability than MOD-026 for DER sites.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment that this is beyond the scope of MOD-026-2 to use system level DME. This collection and use of data is being covered in MOD-033-3 and not in MOD-026-2. IBR, IBR DER, and DER are beyond the scope of MOD-026-2, only registered IBRs are in scope for MOD-026-2. There are in the scope of MOD-032 and MOD-033, but the DT only focuses on registered entities.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC supports the comments of the MRO NERC Standards Review Forum	
Likes 0	
Dislikes 0	
Response	
Please see the response to MRO NSRF's comment.	
Elizabeth Davis - PJM Interconnection, L.L.C. - 2 - RF	
Answer	Yes
Document Name	
Comment	
While in agreement to the question, we have concerns regarding the PRC-028-1 Implementation Plan based on how and when an extension(s) has been granted and management of such IBR information in allowing practical application in validating models.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response and concern with PRC-028-1 implementation. The implementation with all FERC Order No. 901 projects should be completed and fully effective by November of 2030. This should not be a concern with the data received for the MOD-033-3 standard to be able to preform System level Model Validation, fulfilling P85.	

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2, Group Name PJM, MISO, SPP, NYISO joint comments	
Answer	Yes
Document Name	
Comment	
While in agreement to the question, we have concerns regarding the PRC-028-1 Implementation Plan based on how and when an extension(s) has been granted and management of such IBR information in allowing practical application in validating models.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to PJM's comment. The DT has also incorporated in the IP a phased in approach for Requirements R3 along with under considerations information about the EMT exemptions.	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	Yes
Document Name	
Comment	
Comments: ITC concurs that the intent of MOD-026 and MOD-033 will meet the directives in P85 in FERC Order 901 following recommended revisions.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Rhonda Jones - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Danielle Moskop - Ameren - Ameren Services - 1,3,5,6 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Nick Leathers - Ameren - Ameren Services - 1,3,5,6 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Please see the DT's response to EEI's comment.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Steven Belle - Dominion - Dominion Virginia Power - 1,3, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Dominion Energy supports the EEI position.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Xcel Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI’s comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
GOs for existing conventional units are being subjected to unique characteristics of inverter-based resources (IBR), unregistered and aggregated IBR, and aggregated distributed energy resources. FAC-002 already requires an initial model for IBRs for new interconnections. It is recommended to build off FAC-002 requirements for IBRs, potentially creating a standalone procedure or designated IBR MOD-026 requirements.	
Likes 0	
Dislikes 0	

Response	
Thank you for your response. MOD-026-2 Attachment 1 acknowledges the differences in technologies and reflects these in the distinct requirements outlined in Table 1.1 and Table 1.2. The process should remain consistent with the directive in Order 901, P143.	
Adam Burlock - TransAlta Corporation - 5 - MRO,WECC,NPCC,RF	
Answer	Yes
Document Name	
Comment	
However, it is haphazard. It seems that the PC would request DME data from a GO under PRC-028 R7. The PC would be required to assess modelled vs. actual behaviour at least once every 24 calendar months under MOD-033-3 R1.2. A GO would also be required to assess their own facility model performance for qualifying frequency excursions under MOD-026-2 Attachment 2 Row 4. A GO would also assess IBR performance for qualifying events under PRC-030-1, which may consider assessment of model performance.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response, one needs to Model Validate and Model Verification at the generator level to feed into the MOD-033 system level model. The relation of PRC-028-1 to MOD-026-2, there is not direct language in the standards connecting these two standard together.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concern toward this proposed draft fulfilling the FERC Order 901 Milestone 3 directive in P85.	
Likes 0	
Dislikes 0	
Response	
Thank you for the support.	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
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	
Thank you for the comment.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Bob Cardle - Pacific Gas and Electric Company - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Colin Chilcoat - Invenergy LLC - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Daniel Gacek - Exelon - 1,3, Group Name Exelon	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment.	
Chris Wagner - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Karina Valencia - Oncor Electric Delivery - NA - Not Applicable - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Joseph Scott - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for the comment.	
Ijad Dewan - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Sing Tay - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Matt Lewis - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment.	
Scott Thompson - TXNM Energy - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
David Vickers - Vistra Energy - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Kera Schwartz - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Josh Schumacher - Black Hills Corporation - 1,3,5,6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for the comment.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Manish Patel - Silicon Ranch Corporation - 5 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response
Thank you for the comment.

5. Provide any additional comments, including a detailed explanation of any recommended revisions, for the Drafting Team to consider, if desired.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	
MRO agrees with overall MOD-026-2 but has the following comments: MRO recommends clarifying what should be included in a "plan" referenced in Requirements R4 and R6, for example milestone dates, test activities, responsible personnel etc. MRO recommends clarifying and specifying minimum expectations regarding "Model Acceptance" referenced between Requirements R1.3 and R5.	
Likes 1	Nebraska Public Power District, 3, Eddleman Tony
Dislikes 0	
Response	
Thank you for the comment. The plan has been removed in Requirement R4 and R6, this was based on comments provided by EEI and others. The DT has also edited Requirement R5 and Requirement R1, Part 1.3. The Transmission Planners and Planning Coordinators will specify those details, as the DT did not want to get too prescritptive when trying to specify the exact requirements that TPs and PCs will use. The DT felt there is too much variation and that leaving this up to the TP and PC to specify would be better than the DT specifying.	
Manish Patel - Silicon Ranch Corporation - 5 - SERC	
Answer	
Document Name	
Comment	
Requirement R1 The primary concern with the approach outlined in this standard is the potential for inconsistency, as each Transmission Planner (TP) may establish its own set of model verification requirements. As a result, a model considered suitable by one TP might be rejected by another. The standard should include a minimum set of requirements for model verification instead of putting this responsibility on TP.	

Requirement R1 states that "Each TP and its PC shall jointly develop dynamic model verification requirements and processes. The dynamic model verification requirements and processes shall be made available to GO(s) and TO(s) by the TP and shall include at a minimum the following:"

- Why the term "model verification" is not capitalized to refer to defined term?
- The measure M1 uses defined term "Model Verification" at least once, which is inconsistent with the Requirement R1.

The intent of R1 is to focus on "model verification requirements and process.". Part 1.1 and Part 1.2 focuses on model type (positive-sequence and EMT) and details included in the model (limiters, protective functions, etc.). Parts 1.4 through 1.6 are administrative in nature and focuses on information sharing between entities. Part 1.3 is regarding acceptance criteria for models. The focus does not seem to be on model verification requirements.

R1, Part 1.1.1

R1, Part 1.1.1 requires TP to specify limiting and protective functions listed in Table 1.1 that are required to be represented in the model. Then in Table 1.1, it is stated that if required by TP under R1, Part 1.1, TO and GO shall submit models representing enabled limiters and protective functions. This is circular where standard requires TP to specify limiters and protective functions and then states that if required by TP, GO and TO shall provide limiters and protective functions.

Additionally, Part 1.1.1 could be removed all together. Part 1.1 refers to applicable table in attachment 1, which inherently includes intent of Part 1.1.1.

R1, Part 1.2

Part 1.2.1: There should be clear guidance or defined expectations for Transmission Planners (TPs) to identify legacy facilities that require EMT models. Without such direction, a TP could potentially mandate EMT models for all legacy facilities, regardless of necessity. This is of importance given that non-BES IBRs are also included in the applicability of the standard.

Part 1.2.2: What is meant by "acceptable EMT model" and "format"? EMT models are not like positive sequence models where there are various models with varying functionality.

R1, Part 1.3

While the intent of Requirement R1, Part 1.3 is understood, each TP may establish different acceptance criteria. Consequently, a model deemed acceptable by one TP might not meet the acceptance criteria of another.

At minimum, consider revising as follows: Criteria for assessing and determining the acceptability of submitted models and their supporting documentation.

R1, Part 1.5

Who is responsible for submitting documentation of Model Verification and applicable model(s) to the applicable PC? TP or GO/TO?

Footnote 1: Consider using the commercial operation date instead of the in-service date. The term "commercial operation date" is used in recently approved PRC-028-1 standard.

R2, Part 2.2

- Clarify what is meant by “parameters that can be confirmed by the GO or TO”.

R2, Part 2.1 & 2.3

- Part 2.1 requires that model represents the in-service equipment of the facility according to the requirements and process developed in R1. R1, Part 1.1, refers to attachment 1 as well. Then R2, Part 2.3 refers to Attachment 1 as well. It appears that Part 2.3 is inherently included in Part 2.1. Consider removing Part 2.3. As written, sends conflicting message.

R3, Part 3.1

- The standard should further include details of what is meant by “large signal disturbance”?
- It is stated that if test results are not obtainable, the GO and TO shall document the reason. Does this statement apply to Facility’s already in-service or future facilities as well?
- Part 3.1, 3.4, 3.5, and 3.6 are a part of Model Validation and Model Verification process. Requirement R1 requires TP/PC to develop Model Verification process. So then why are the parts of the Model Verification Process listed in the standard itself?

R3, Part 3.2

- The intent of Part 3.2 is like Requirement R2, Part 2.1. The requirements and process developed in R1 are referenced in R2, Part 2.1. But R3, Part 3.2 does not refer to requirements and process developed in R1. This is confusing.
- What does “that can be confirmed by the GO or TO” mean?

R3, Part 3.3

- What is meant by auxiliary control devices? Are these the same as auxiliary motors, pumps, etc., that support the facility? If so, not sure of all those are reflected in EMT models currently.

R4

- Both options listed as bullet points are already covered in Attachment 2, Row 6. There is no need to repeat those in Requirement R4.

Attachment 1

- The title of Attachment 1 is “Applicability”, which is confusing. The appropriate title may be “Positive-sequence dynamic model details”.
- Table 1.1, Excitation Control, item #3, could be improved for ease of readability. Consider revising as follows: Model Validation of the positive sequence dynamic model(s) using the recorded dynamic reactive power response of the facility during either a staged test or an actual system disturbance. The same change could be carried over to language under generator model and governor control in Table 1.1 and respective aspects in Table 1.2.
- Table 1.2, Volt/Var Control, 1.a.i. à What is meant by IBR unit(s) electronic control?
- Table 1.2, Frequency/Power Control, 1.a.i. à What is meant by IBR unit(s) electronic control?

Attachment 2

- Row 5 is missing. Table jumps from Row 4 to Row 6.
- The title of the second column “modeling condition” is not appropriate. Consider changing this to “triggering condition”.
- Row 4: References Row 5, which does not exist.
- Row 8: In second column, Requirement R6 should be Requirement R4.
- Note 1: The use of “unit” is inappropriate. The “facility” should be used instead to read as follows: The facility Model Validation frequency excursion criteria.
- Clarify that row 13 does not apply to synchronous condensers, FACTS devices, and HVDC lines.
- Row 14: As written, if the commissioning date is before the effective date of MOD-026-2, then facility is exempt from R3. The first “OR” should be removed. This would then exempt legacy Facility where the OEM is no longer doing business in North America OR the OEM no longer supports models of in-service equipment.
- Rows 12, 13, and 14 uses “Facility” with capital “F” but elsewhere in the standard “facility” is used. Is there a reason for this?

General comments

- Applicability à Facilities à 4.2.3: “but not limited to” is stated at the end in 4.2.3, however, it has no meaning. The rest of the standard specifically calls out 4.2.3.1 (synchronous condensers) and 4.2.3.2 (FACTS devices). Remove “but not limited to” and clearly state that standard applies to facilities with synchronous condenser and FACTS devices meeting the criteria set by inclusion I5 of the BES definition with a gross nameplate rating greater than 20 MVA.
- Model Validation Requirement for positive-sequence model is embedded in Attachment 1, Tables 1.1 and 1.2. But those are spelled out in Requirement R3, Parts 3.4, 3.5, and 3.6 for EMT model. This is confusing.
- It is not clear why details included in Attachment 1 are necessary in MOD-026-2. MOD-032 already requires TP to develop modeling data requirements. Attachment 1 in MOD-032 already details which components of the Facility are to be included in the model. Perhaps Attachment 1 in MOD-032 could be enhanced a bit. The details in Attachment 1 in MOD-026-2 could be removed then as the focus of MOD-026-2 is Model Validation and Model Verification process.
- Equivalent of R2, Part 2.4 (provide updated model within the applicable periodicity timeline in Attachment 2) is not included in R3 for EMT models. Why?

Likes 0	
Dislikes 0	

Response

Thank you for your comments and suggestions.

Regarding Requirement R1, the DT acknowledges that there is a potential for models acceptable to one Transmission Planner (TP) to be unacceptable to another. However, the DT notes that the existing MOD-026-1 and MOD-027-1 standards operate in much the same way. If the TP finds the model unacceptable, there is a resolution process which includes an option for the GO/TO to provide a justification for maintaining the model it has already submitted. The DT is not in the position to determine what constitutes an acceptable model for all TPs and all systems. The DT has modified Requirement R1 to remove the term “model verification”. The language now refers to dynamic “model requirements for the purpose of Model Verification and Model Validation”, which is more appropriate for the subparts. This also addresses confusion and inconsistency relative to the defined term, “Model Verification”. The requirements developed under Requirement R1 concern the models and accompanying documentation of Model Verification and Model Validation, as outlined in the subparts of Requirements R2 and R3.

The DT has clarified in Part 1.1.1 that the TP/PC are to specify “which” limiting and protective functions they need modeled. This was the original intent, but the meaning was not clearly conveyed.

Regarding Part 1.2.1, and similar to the response above for Requirement R1, the DT is not in a position to determine precisely which facilities require EMT models for every system. TPs are expected to identify facilities that need models based on a technical rationale or a technical guideline. The need for models is expected to vary due to penetration level of IBR, FACTS, and HVDC facilities, system strength, existing reliability concerns, etc. For legacy facilities where an EMT model is not obtainable, the MOD-026-2 standard allows for exemption from Requirement R3. The DT has attempted to strike a fair balance between the need to verify and validate the models used for evaluating system reliability, and the potential difficulty of obtaining of such models.

Regarding Part 1.2.2, the TP is to specify their requirements for submitted EMT models such that GOs and TOs have a clear understanding of what constitutes an acceptable model for the TP. Format may include items such as compatibility with a specific EMT program (e.g., PSCAD), time step requirements, etc.

Regarding Part 1.3, the DT finds the suggested language aligns with the intent of the posted language. Similar to above, TPs are required to make their expectations known to GOs and TOs responsible for submitting models. The DT has clarified the expectations under Part 1.3 by rewording to ensure that any requirements for models and accompanying documentation that are used to assess model submissions are made available to GOs and TOs.

Regarding Part 1.5, model and documentation submissions are required from the GO/TO, and are provided to the TP/PC. However, this part has been removed as the required action of submitting the models and accompanying documentation are adequately covered in later Requirements. The DT opted to remove administrative, process-oriented requirements.

Regarding footnote 1, the DT has taken the suggestion to use the commercial operation date.

Regarding Part 2.2, the DT has clarified that the GO/TO are to make the TP aware of any parameters in the model that they are unable to verify. This may include parameters that are provided by OEMs and that represent internal settings not configurable by the GO/TO. This aspect has been moved into Part 2.2.1.

Regarding Parts 2.1 and 2.3, the DT has restructured Requirement R2 to address this issue. Part 2.1 now address the provision of model(s) that include the component of Attachment 1 in accordance with the model requirements developed in Requirement R1. The link to R1 is maintained because the dynamic model requirements there specify the limiting and protective functions required (see Part 1.1.1), and because the requirements may add detail or restrictions to the way the other models in Attachment 1 are represented. For example, a Transmission Planner may preclude certain models from being submitted due to identified model issues or errors. For GOs or TOs complying with Part 2.1, care should be taken that the models and accompanying documentation meet the Transmission Planner's requirements.

Regarding Part 3.1, large signal disturbances are expounded upon in the Technical Rationale. The DT does not think that these details are necessary to integrate into the standard, and it would be overly prescriptive to do so. The DT also notes that this Part has been moved to Part 3.4, and the scope has been limited to IBR units. The requirement to provide a documented reason test results are not obtainable applies to both in-service and future facilities alike. The DT recognizes that some facilities utilize equipment where test reports for large signal disturbances may not be available. While GOs are encouraged to work with equipment manufacturers to procure these results, the DT did not think that these situations should rise to the level of non-compliance.

Regarding Part 3.2, the DT has restructured Requirements R2 and R3 to clarify the parallels and provide consistency. Parts 2.2 and 3.2, as well as Parts 2.2.1 and 3.2.1 are now identical. This clarifies the DT's intent that both the positive sequence models (Requirement R2) and the EMT model (Requirement R3) have documentation of Model Verification, and that parameters that cannot be verified are documented and explained.

Regarding Part 3.3, footnote 8 clarifies that the only auxiliary control devices that are required to be modeled are those that act on voltage or frequency.

Regarding Requirement R4, the requirement has been modified to consolidate information in Attachment 2 into the requirement language. This requirement no longer references Attachment 2. This approach improves the clarity of the standard as it locates all of the relevant information for Requirement R4 in one place.

Regarding Attachment 1, the title was an unintentional error. Attachment 1 is always referred to as "Attachment 1" and does not have a title. Model Validation requirements have been moved out of Attachment 1 and into Requirement R2. This improves consistency between Requirements R2 and R3, and results in better parallels between the documentation requirements for Model Verification and Model Validation. IBR unit(s) electronic control refers to any control systems affecting the power output of the inverter at the inverter level. This is distinguished from the facility's power plant control in item (a)(ii).

Regarding Attachment 2, the DT has made significant modifications to address multiple issues identified with Attachement 2. The DT appreciates the detailed list of suggestions and has incorporated most of these into the updated table. As requested, row 13 (now row 9) has been clarified to exclude facilities where capacity factor is not applicable. The exemption of row 14 has been integrated into Requirement R3 and simplified to avoid confusion with the logical conditions. Due to the inclusion of non-BES IBRs in the standard, the defined term "Facility" is not always appropriate. The DT has utilized the lowercase "facility" throughout to prevent exclusion of these non-BES generators.

Regarding Applicability 4.2.3, the wording has been updated to align with section 4.2.4.

Regarding Model Validation requirements, these are now located in parallel locations: Requirement R2 Part 2.3 and Requirement R3 Part 3.3. The DT hopes this improves the readability and clarity of the standard.

Regarding the relationship with MOD-032, the DT does not intend to create conflicting requirements. However, MOD-026-2 does stand as a model collection standard. The model collection under MOD-026-2 is more detailed and has additional requirements (e.g., Model Verification and Model Validation) that are not explicitly required under MOD-032. Further, there is a resolution process under MOD-026-2 that is not present in MOD-032. And finally, MOD-026-2 requires model updates after certain changes (e.g., setting changes) whereas MOD-032 only requires models at a specific cadence. The DT envisions that models submitted and accepted under MOD-026-2 will then be submitted under MOD-032 until model updates are made. The DT working on NERC project 2022-02 to edit MOD-032-2 has included a requirement in the most recent draft of MOD-032-2 that requires models accepted under MOD-026 to be submitted if such models are available.

Regarding model submission periodicity, the DT has included this into the body of Requirement R2 for consistency and clarity.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	

Comment
FirstEnergy also offers the following comments: In all cases, periodicity/timeframes should be embedded in any time-based Requirements, not in Attachments. Requirement R2 language as written does not clearly include Model Validation. This term is only found in footnotes and Attachments. If the Requirement is intended to prescribe both Model Verification and Model Validation, both of those terms should be explicitly embedded in the Requirement and formatted as listed in the Glossary of Terms. Regarding Requirement R3, o IBR/Solar controlled largely by the TO, transmitted via SCADA; building a verified model will require extensive coordination. The TO is not tasked to respond/coordinate by any Requirements; suggest adding time-based Requirement to ensure proper response to coordination/information requests between parties. o Since IBR/solar controls are spread across GO/TO systems, validation testing would also be a significant challenge. Requirements should be included to mandate collaboration if this is expected to occur. o It is unclear how Model Validation of IBR's will be achieved, especially since details will be later defined by the TP under R1. The unpredictability/variability of available power, as well as the unclear means of measuring available power, leaves too much uncertainty for the GO. Exception statements should be included in the Requirement, and/or guidance allowing for alternate means of validation, in cases of absence of optimal testing conditions. FirstEnergy also supports EEI's comments which: EEI provides the following comments for consideration: Applicability: o 4.2.6 No changes o 4.2.7 Recommend deleting Requirement 1 • Use of uncapitalized "model verification" could be confusing given the defined term. EEI suggests the following: o Each Transmission Planner and its Planning Coordinator shall jointly develop dynamic model**ing** requirements and processes **to validate the dynamic model(s)**. The dynamic model requirements… • The relationship of R1.3 to R1.1 and R1.2 is unclear, it seems R1.1 and R1.2 must also be part of the acceptance criteria. EEI suggests the following:

Delete R1 Part 1.3 and revise R5:

R5. **Each Transmission Planner shall establish acceptance criteria to determine disposition of submitted model(s) and accompanying information.** Each Transmission Planner **shall use the developed criteria to review each submission** after receiving the submitted model(s) and accompanying information from the applicable Generator Owner or Transmission Owner and provide a written response to the submitter within the timeframe in Attachment 2. The written response shall include one of the following:

o Notification of acceptance: the model and accompanying information meet the acceptance criteria established in Requirement R5.

o Notification of denial: the model and accompanying information does not meet the acceptance criteria established in Requirement R5, or the information submitted was incomplete. The notification of denial shall include an explanation and supporting evidence.

Requirement 2

• R2 should reference Model Verification and Model Validation rather than using “verified model”. EEI suggests the following:

o R2. Each Generator Owner or Transmission Owner shall provide **to its Transmission Planner: models that have documented Model Verification and Model Validation, documentation** of Model Verification of a positive sequence dynamic model(s) with associated parameters, and any information pertaining to changes to the model(s) or its parameters. The Generation Owner or Transmission Owner shall include documentation that:

• R2.2 should be more aligned with the Model Verification definition. EEI suggests the following:

o R2.2 Verifies that the configurable, site-specific parameters of the model(s) **structure and parameter values** represent parameters of the in-service equipment of the **or** facility **design and setting**, for those parameters that can be confirmed by the Generator Owner or Transmission Owner. A

• Periodicity in R2.4 should be deleted and included in part of the main requirement language. EEI suggests the following:

o R2 Each Generator Owner or Transmission Owner shall provide: documentation of Model Verification of a positive sequence dynamic model(s) with associated parameters, any information pertaining to changes to the model(s) or its parameters, and the Model Verification and Model Validation model(s) to its Transmission Planner **within 365 days after commissioning for initial verification for a newly commissioned facility or within 10 calendar years of the most recent transmittal** that:

Requirement 3

Conducting the two staged tests could degrade reliability, operational flexibility, and market operation of the real time system when they are conducted. EEI suggests the following:

o 3.1. Test **or simulated study** result(s) demonstrating a comparison of the facility’s response and the facility’s EMT model response for large signal disturbances. For an IBR, the Generator Owner shall test and compare only the IBR unit. If test **or simulated study** results are not obtainable, the Generator Owner or Transmission Owner shall document the reason;

o 3.2. Documentation of Model Verification demonstrating that the configurable, site specific parameters of the submitted facility model(s) represent parameters of the in-service equipment of the facility, for those parameters that can be confirmed by the Generator Owner or Transmission Owner;

o 3.3. A facility EMT model with associated parameters representing the applicable HVDC, FACTS devices, IBR unit(s), collector system, auxiliary control devices,8 power plant controller, generator step-up transformer, and main transformer(s) shall include:

o 3.3.1. Enabled protections that directly trip the IBR unit(s) or facility;9 and

o 3.3.2. Limiting functions that limit active/reactive output of the IBR unit(s) or facility.

o 3.4. Documentation of Model Validation of the facility EMT model response using the recorded **or simulated** response of a dynamic reactive power or voltage event from **a simulated test**, a staged test, or a measured system disturbance;

o 3.5. Documentation of Model Validation of the facility EMT model response using the recorded **or simulated** response of a dynamic active power or frequency event from either **a simulated test**, a staged test, or a measured system disturbance in which the power plant controller's or other facility active power controller's perceived frequency deviations are in accordance with Attachment 2, Note 1; and

o 3.6. Documentation comparing the **simulated or recorded** large signal disturbance response of the facility positive sequence dynamic model(s) provided in Requirement R2 to the **simulated or recorded** response of the facility EMT model.

Requirement 4

• Recommend connecting the update to any change that affects the model rather than referring to the dynamic response. Some GO/TOs may not be aware that a change they made alters the response. If the setting is in the model, then a change in the setting should require a model update. EEI suggests the following:

o R4 Each Generator Owner or Transmission Owner, upon making a hardware, software, firmware, control mode, or setting change(s) to any in-service equipment specified in Requirement R2 or Requirement R3 that **model**,…

• Providing a "plan" is not sufficient. A timeline should be included. EEI suggests the following:

o A plan, **including the timeline,** to provide the verified model(s) and associated information in accordance with Requirement R2 or Requirement R3.

Requirement 6

• The option to provide a "plan" is not satisfactory. A timeline should be placed on the correction. EEI suggests the following:

o A plan, **including the timeline,** to submit the verified model and accompanying information in accordance with Requirement R2 and Requirement R3

• The third option appears redundant with the first option. Consider removing it.

Attachment 2

• For facilities that require EMT models, both PSPD and EMT models should be delayed such that they can be submitted together.

• Row 2: The term “commissioning date” is undefined and unclear. EEI suggests the following:

o Transmit the verified model and accompanying information to its Transmission Planner within 365 calendar days after the commissioning date.

• Row 3, Consider only including the “most recently approved submittal” rather than include the confusing 2nd paragraph.

• Row 5 is missing.

• Row 6 The timeline should be included in Requirement R4. EEI suggests the following:

o …shall provide its Transmission Planner with one of the following, within **180 calendar days after the facility is returned to service subsequent to making a change to inservice equipment**.

• Row 7 should be removed, and the timeline included in Requirement R4. EEI suggests the following:

o R4…shall provide its Transmission Planner with one of the following, within **365 calendar days after the submittal of the plan to verify the model.**

• Row 8 a timeline should be included in the Requirement to allow all the expectations of the requirement to be understood in one location. EEI suggests the following:

o R5 ...and provide a written response to the submitter **within 120 calendar days from receiving each submission**.

• Row 9 is inconsistent with row 6. It is unclear while a failed model under R6 should have less time for correction than a model that receives a setting change. EEI suggests the following:

o Provide a written response to its Transmission Planner within 1**80** calendar days

• Row 10 is not entirely a timing requirement, it is setting conditions that allow for the model of one unit to be used for another. Should this be in the requirement language?

• Row 13 should this be merged with row 3 and explained as an exemption?

• Row 14 is not a timing requirement. This is directly related to R1.2.1. Row 14 should be addressed in the Standard. EEI suggests the following:

R3.7 Document in a declaration to its Transmission Planner that an EMT model is precluded for one of the following: the commissioning of the applicable legacy facility (before the effective date of MOD-026-2); OR The original equipment manufacturer (OEM) is no longer doing business in North America; OR The OEM no longer supports model(s) for in-service equipment at the Facility.

Likes 0	
Dislikes 0	

Response

Please see the DT's response to EEI's comment.

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

Answer	
Document Name	

Comment

Requirement R1 uses model verification both capitalized and non-capitalized. If the intent is not to use the new Model Verification term, please clarify the distinction, or revise the text appropriately.

Requirement R1 Part 1.2.1 references "legacy facilities" and makes use of a footnote to define this term. As this pertains to the Standard's applicability, it would be more appropriate to incorporate the in-service date criteria within the Applicability section of the Standard. Furthermore, as the Applicability section as currently drafted does not have any exclusion based on the in-service date, it is not clear how the exemption in the Footnote 1 can be implemented to ensure regulatory compliance to R1 including Part 1.2.1; as written, Requirement R3 (referenced in R1 Part 1.2.1) applies to all facilities responsive to the Applicability sections it references.

Requirement R2 as drafted, i.e." […] its Transmission Planner that:

2.1 Verifies that the model represents the in-service equipment of the facility according to the requirements and process developed in Requirement R1;

2.2 Verifies that the configurable, site-specific parameters of the model(s) represent parameters of the in-service equipment of the facility, for those parameters that can be confirmed by the Generator Owner or Transmission Owner.

2.3 Verifies that the model includes at a minimum each of the information described in Attachment 1; and 2.4.

2.4 Is updated within the applicable periodicity timeline outlined in the Periodicity table in Attachment 2."

may benefit from additional clarity that the Parts 2.1 through 2.4 refer to the provision of documentation/information/model rather than the TP.

To avoid possible confusion on TP responsibilities, recommend revising to "Each Generator Owner or Transmission Owner shall provide to its Transmission Planner […]"

Attachment 2: Table is missing Row 5. This Row 5 is referenced in Row 4. Requirements R5 and R6 allow the GO/TO to, subsequent to a TP denial, resubmit a model with additional technical justification. However, as the GO/TO have no input in the acceptance criteria set by the PC and TPs in accordance with R1 Part 1.3., there could be situations where a dispute resolution process may be required to resolve technical disagreements.	
Likes 0	
Dislikes 0	
Response	
The DT has clarified and removed the non-defined term of model vladiation in Requirement R1. The alternate wording now removes “validation” based on industry feed back. Row 5 and Attachment 2 has been edited and corrected. The DT has edited Requirement R2 and the sub parts to follow the style Requirement R3 was wrote. The DT has accepted and corrected the language in the standard to match with what was recommended. The DT has removed the wording Requirement R1, Part 1.3 from Requirments R5 and Requirement R6. The DT has also reworded these requirements to flow correctly with Requirment R1 and its subparts. Thank for you for pointing this out, this should now be corrected in the additional ballot 1 posting.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
In Attachment 2, Row 5 is missing.	
Likes 0	
Dislikes 0	
Response	
Thank you, this has been corrected.	

Diane E Landry - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name CHPD	
Answer	
Document Name	
Comment	

CCPUD appreciates the draft being more prescriptive of the dates and timelines for model provisions. Further comments of each section of the draft are below.

R1 Commentary:

In the current MOD-026/27 R1, there is a requirement for the TP to provide a list of acceptable models to the GO. Inherent in this is for the TP to have a list of acceptable models, which is important because it sets an expectation that the models provided will be use-able to the TP. This specific language has been removed from the new MOD-026-2 R1; one may argue the requirement is more generally encompassing by allowing TP/PCs to set up requirements and processes, but as this idea of a model list is now absent, it may be lost in processes going forward. This construct of the model list is captured in the proposed MOD-026-2 R1.2.2 for EMT models, but this revision is silent on a list for positive sequence models.

For new MOD-026-2 R1.3, speaking to criteria for acceptable criteria for 'disposition' of submitted models – this is all well and good, but a greater challenge in performing simulations is there needs to be a larger system-side EMT model in order to perform reasonable simulations of performance. These larger-system EMT models do not generally exist currently, and there are no new requirements to have and develop larger system EMT models. Additionally, the term "disposition" lacks clarity—consider refining or removing it..

In the proposed MOD-026-2 R1.2.1, this is under the R1 header for model verification requirements and processes. These are more general forms of documentation. R1.2.1 requires TP/PCs to Identify which legacy facilities EMT models will be required – it is unclear if this requirement is in the general form, or if this ask is to develop an actual list of actual facilities that need new EMT models for legacy facilities. If it is the general form, then MOD-026-2 R3 does not make sense; but if a specific list, then it makes more sense. It would be helpful to clarify the expectation of where the list should be created, and who is responsible for creating it.

For R1.5, it is not clear who is responsible for submitting model data to the PC – is this a TP obligation or a TO/GO obligation? Or is this intentionally left vague and is assumed the PC and TP will coordinate on the assignment of this obligation? If so, R1.4 is prescriptive in assigning the GO/TO to provide data to the PC, so R1.5 is not consistent and needs clarity.

R2 Commentary:

MOD-026-2 R2.2 requires the GO/TO to provide site-specific model parameters, ensuring alignment with on-site settings. However, modeling is both an art and science—effective modeling should prioritize accurate system response over rigid adherence to equipment settings. Mandating exact replication may degrade model quality.

R3 Commentary:

Same as R2 commentary for R3.2, concerning site-specific parameters.

R4 Commentary:

Similar to commentary on MOD-026-2 R2.2 regarding negligible change in settings or impact, R4's requirements regarding 'change' add unnecessary and non-useful burden for small changes that result in negligible impact to model performance and system response. As noted in R2, there should be some change-threshold or impact-threshold allowed where small negligible changes to settings do not require model revisions.

R5 Commentary:

None

R6 Commentary:

In the prior draft of MOD-026-2, the mechanism for a TP to request a review/update of a model had been dropped from the current in-effect MOD-026 and 27 R3. CHPD supports the new add to MOD-026-2 R6, which includes this language.

Footnote Commentary:

Footnote 11b Commentary: The term "deploy" in Footnote 11b is ambiguous, as protection systems may be implemented in arming-only modes or perform functions beyond tripping a generator. To clarify intent, the language should specify that such settings are intended to trip the generation resource(s) rather than broadly referencing deployment.

Attachment 1 Commentary:

The table header "Applicability" is misleading, as its contents align more with Positive Sequence Data Requirements rather than applicability itself.

For the Generator Model, Excitation Control, and Governor Control, all entries have language to the effect "Models representing the …(respective device). This language is off-target – the models do not necessarily represent these devices, but rather they model how the models respond to changes to the electro-mechanical system. To clarify other cases, this is not a thermal model; it is not a vibration model, etc. – the focus is on the electro-mechanical response, and the language should be modified to focus on this.

Under excitation control, there is an inclusion of a vague phrase 'outer loop controls which impact dynamic volt/volt-ampere reactive (VAR) performance'. It is not clear whether this outer loop is considered plant level AVR or system level AVR or other voltage control. As far as contents and requirement reciprocity go, Governor Controls have excluded Automatic Generation Control, so in that line of things, it seems odd that the more outer voltage control is included for excitation control. As a secondary support for removing the outer voltage control from this table, it is also noted the time response of these outer loops is regularly much greater than the response time and system stability phenomenon entities use for stability simulations. Thus, the value of having such long-term models for positive sequence dynamics modeling is limited.

Under 'Additional Limiting and Protective Functions', item 2 lists a number of items for protective relay models. However, it is not clarified that these are in the context of positive sequence modeling – I could have an AC under-voltage relay either on a single-phase imbalance or three-phase imbalance in the field, but in this modeling context, only the three-phase instance makes sense for application of this requirement. This should be clarified in the language of this table item. Also, the list of items seems to run on without a final ‘or’ before out of step protection. This should be added in to provide the proper logical context of the list.

Under ‘Additional Limiting and Protective Functions’, it is recommended the list of protective relays also include loss-of-excitation relays, phase distance, and phase overcurrent modeling, which is useful for PRC-026 work for relay performance during stable power swings. The caveat here is the PRC-026 Attachment 1 language limits these relays with a time delay of less than 15 cycles and are “load responsive”, so such an addition may consider alignment with the PRC-026 qualifiers. Time delays 30-60s may be in the realm of useful, but anything greater than 60 seconds is likely beyond the scope of realistic stability simulations in practice.

Attachment 2 Commentary:

As an end-user, the Attachment 2 table construct with date items 1-14 (note item 5 in the table is missing) is at best difficult to navigate. Functionally, it feels like its own standard. It is recommended each applicable deadline be moved into each of the respective main-standard requirements; the use of this table construct is less helpful, rather than clarifying.

Likes 0	
Dislikes 0	

Response

The DT has refined the wording for Requirement R1 Part 1.3 for better clarity and based on comments. The DT decided to not remove it after discussion.

The DT did not want to be too prescriptive when writing this standard, and felt that it should be the TP and PC responsibility to define what is needed from the GO and TO to produce in models.

For Requirement R1, Part 1.5 has been incorporated in Requirements R4 – R6. It has been removed out of Requirement R1.

R2 Commentary:

The DT has reviewed and modified Requirement R2 and its subparts. These new edits should address the concerns.

R3 Commentary:

The DT reworded Requirement R3 and the subparts, similar to Requirement R2 and should address concerns.

R4 Commentary:

The DT disagrees as a change needs an updated model for Model Valdiation that needs to be communicated to the TP. This change is necessary and an updated needs to be provided.

R6 Commentary:

Thank you for the support.

Footnote Commentary:

The DT has removed the footnote, and clarified footnotes.

Attachment 1 Commentary:

The table header has been removed.

Being based off the definition of Model Validation, the team has focused the wording to accurately reflect the way the definition was written. The wording should match and was intentional. The team felt all wordings in Attachment 1 repersented the team's ideas and what was trying to be conveyed and the way it needed to be conveyed.

Under 'Additional Limiting and Protective Functions' the team has made conforming edits to add clarity.

The team feels TP and PC will choose the additional protective funcations that need to provided for Table 1.1, but Table 1.2 all are necessary to provide. The team made Table 1.1 the additional protective functions that need to be provided due to to not putting any more burden on traditional synchronous generation.

Attachment 2 Commentary:

The DT has removed multiple rows and added them back into the language on the Requirement body. The DT has also clarified a lot in the table to make it as clear and concise as possible.

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	
Document Name	
Comment	

Thought Consumers Energy is still concerned with the inclusion of less impactful IBR generation, we feel confusion remains with the statements made in 4.2.6 and 4.2.7. Using BES Exclusion 1 or 3, a 50 MVA, 69 kV-connected IBR unit could fall into the facilities defined in both 4.2.6 and 4.2.7. We are also concerned with the use of "or" in the Standard. The Standard appears to provide an option between two parties, GO and TO, to report to the TP. Clarifying language addressing Applicable Facilities would solve this. "For facilities specified in sections 4.2.3.2, 4.2.4, 4.2.5, and 4.2.6, the respective Generator Owner or Transmission Owner shall provide…."

Likes 0	
Dislikes 0	

Response	
The drafting team (DT) has removed Section 4.2.7 under the *Facilities* section in response to stakeholder comments, aiming to eliminate confusion within MOD-026-2. After consultation with NERC Legal, it was confirmed that the term **"respective"** does not need to be added, as the *Applicable Facilities* section already provides sufficient clarity. To maintain consistency with the language and style of other standards, the DT will not include the word "respective."	
Adam Burlock - TransAlta Corporation - 5 - MRO,WECC,NPCC,RF	
Answer	
Document Name	
Comment	
Footnote 1 - "any facility with an in-service date prior to the effective date of MOD-026-2" potentially conflicts with Attachment 2 Row 14 "commissioning date of the applicable legacy facility". In-service date may be different than commissioning date. Requirement 3 Part 3.3 "auxiliary control devices". What are these? Open to entity interpretation? Footnote 8 "that act on voltage and/or frequency". What does this mean? This is different than similar language in footnotes 9 and 10 "act on quantities derived from voltage, frequency, and/or current" Requirement 3 Part 3.6, "comparing large signal disturbance response" is open to entity interpretation. The Technical Rationale (page 9, second paragraph) includes the following language " The specific large-signal simulation tests that must be run on both EMT and positive sequence models for benchmarking comparisons should include…" If it is a must, then authoritative language needs to be included in the requirement language rather than in the Technical Rationale, or leaving it to the descretion of the TP in Requirement R1, Part 1.3. Footnote 11 "PED" What is this? Requirement R5 - The Lower Violation Risk Factor should be increased to Medium. It seems that by assigning Requirements R2, R3, and R4 a Medium Violation Risk Factor, the standard drafting team is putting an appropriate level of importance onto the GOs and TOs to create and sustain their facility models. There should be similar level of importance put on the TPs to review the submissions in a timely manner in order to realize the anticipated benefits to BPS reliability of having accurate dynamic models. Attachment 1, Applicability Tables 1.1 and 1.2. These tables are better suited for MOD-032, given the language in the Technical Rationale for Part 1.1 "MOD-026-2…requires that the requirements and processes being developed under Requirement R1 include the model specifications from MOD-032. It is not creating new specifications for what is required." Attachment 2 Rows 4 and 14 - these are new scenarios which do not exist in MOD-026-1 and MOD-027-1, yet no explanation is provided in the Technical Rationale	

Attachment 2 Row 4 - "Applicable facility with installed and operating recording equipment does not experience a frequency excursion." Should this read "DOES"? Given that the required action is to transmit verified model and accompanying information to its TP on or before 365 calendar days after a frequency excursion. Attachment 2 Row 14 - is unclear. Should it read "Commissioning date of the applicable legacy facility is before the effective date of MOD-026-2, AND 1. The OEM is no longer doing business in North America OR 2. The OEM no longer supports model(s) for in-service equipment at the Facility?

Likes 0	
Dislikes 0	

Response
The DT changed In-service-date to commercial operation date in Footnote 1. Requirement R3, Part 3.3 Auxiliary devices intended to include statcoms, SVC, etc. Footnote 8 is intended to reference auxiliary systems such as supplementary Var systems (SVCs, statcoms, etc) Requirement 3 Part 3.5 was reworded for clarity. PED refers to Power Electronic Device. The DT has removed footnote 11 moving this to the Technical Rational Document. The VRF's will be reviewed and will remain at the same level if deemed correct or upgraded. The VRFs initially were rated this as they were carried over from MOD-027-1 and MOD-026-1 with this rating. Attachment 1, Tables 1.1 and 1.2 list specific models that need to be verified and validated and therefore the DT believes this needs to be included in the new MOD-026-2. Attachment 2, Row 4 was a carryover from MOD-027-1 Attachment 1, Row 3. Attachment 2, Row 14 has been deleted and moved into Requirement R3 subparts, along with the technical rationale document. Attachment 2, Row 4 is a carryover from MOD-027-1 Attachment 1, Row 3. It is intended to provide for more time to complete validation of frequency response to the extent an actual system event does not occur within the periodicity requirement. The DT has moved this into Requirement R3 and has reworded it in order for legacy facilities with one of the following conditions would be exempt from providing an EMT model for facilities identified by the TP/PC in R1.2.1: 1) OEM is no longer in business or 2) OEM no longer supports in-service equipment.

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE supports EEI's comments as proposed for standard MOD-026-2.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Josh Schumacher - Black Hills Corporation - 1,3,5,6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with EEI's additional comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Kera Schwartz - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	
Document Name	
Comment	

Southern Indiana Gas and Electric d/b/a CenterPoint Energy Indiana South (SIGE) supports EEI's comments on the revisions to standard MOD-026-2.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Chantal Mazza - Hydro-Quebec (HQ) - 1,5 - NPCC	
Answer	
Document Name	
Comment	

1. Modifications to R1-1.1.1.

The goal of R1 is to "develop dynamic model verification requirements and processes".

R1-1.1.1 indicates: "Specify the limiting and protective functions listed within Table 1.1 that are required to be represented in the model"

This is not a verification requirement or process; it is a modelling requirement which is not the intended goal of MOD-026.

R1-1.1.1. should be removed.

2. Modifications to R1-1.2.-1.2.1. and 1.2.2.

This should not be part of the "Verification and Validation" document.

This is a modelling requirement. FAC-002-5 currently being developed by NERC project 2022-04 covers this by requiring TP/PC to develop and publish their EMT modelling requirements (in R1-1.1.).

R1-1.2. should be removed.

3. Modifications to R3-3.3. is a modelling requirement. It should be rephrased to verify this information is included to the model.

4. MOD-026, as proposed, covers verification and validation of models. It should also cover model quality assessment (the process of evaluating the plausibility, usability and numeric stability of a model based on a review of model documentation, data, and simulations), by the TP/PC to ensure the modelling requirements are met and the model can be used for the intended studies. MOD-026 seems like the standard who should cover this.

- Note 1 for Quebec should be removed. We suggest referencing the methodologies established to evaluate the models to indicate when a frequency event can be used to validate the model. (May also vary with the technology being tested).
- In Row 14 of attachment 2, the modelling condition seems to apply only to R3 (EMT). However, the same reasoning can be applied to R2, with difficulties obtaining a phasor domain model. Will R2 be included in the exemption?

5. Synchronous facilities versus IBR (sections A.4.2.1 and A.4.2.2)

In Sections A.4.2.1 and A.4.2.2, it should be explicitly stated that the individual unit or plant/facility refers to synchronous generation. Without this clarification, these sections could be interpreted as applying to Inverter-Based Resources (IBRs), which does not appear to be the intended scope.

6. Model Verification and Validation for synchronous facilities (requirement R2).

6.1 Major component independent compliance
Given that generator/exciter verification and validation activities are typically conducted:

- According to a dedicated schedule,
- By specialized personnel,

…which are independent from the verification and validation of the prime mover/governor and protection systems, it is recommended that Requirement R2 be restructured to allow for independent compliance for each major component of the facility, in a similar fashion than the existing MOD-026-1 (generator/exciter) and MOD-027-1 (prime mover/governor) standards.

Proposition for new structure: R2.1 for generator/exciter, R2.2 for synchronous condenser/exciter, R2.3 for prime mover/governor and R2.4 for protection system. This structure would facilitate the clear assignment of each sub-section to the relevant Subject Matter Expert (SME) within each organization, ensuring more efficient collaboration and review.

6.2 Generator Model Validation

Compared to MOD-026-1, the updated standard MOD-026-2 introduces a new requirement: the validation of the generator model in conjunction with excitation system and governor Model Validations (see Note 12 of Table 1.1). It is common practice to perform generator Model Validation in conjunction with excitation system Model Validation, as the excitation system directly controls the generator's dynamic response.

However, performing generator Model Validation in conjunction with governor Model Validation raises significant concerns, due to the following reasons:

- Including the generator model in the governor control Model Validation would necessarily require the inclusion of the exciter model as well, since the generator model cannot operate independently in a closed-loop configuration. This implies that the entire unit—comprising the generator, exciter, and governor models—would need to be validated simultaneously. This presents a significant concern, as each applicable unit typically follows separate compliance schedules for MOD-026-1 and MOD-027-1. For example, a given unit might have a MOD-026-1 deadline in 2028, while its MOD-027-1 deadline is set for 2030. Moreover, Model Validation relies on tests conducted on in-service equipment, which are usually performed during scheduled maintenance. However, the maintenance schedules for the exciter and the governor are not necessarily aligned, further complicating the coordination of a combined validation effort.

- The governor controls the turbine, not the generator. The dynamic response of the turbine-governor system involves significantly slower time constants compared to the generator-exciter system. Because of this difference, it is technically sound and common practice to perform Model Validation of these systems independently.
  Proposed change: At Table 1.1 in Attachment 1, merge the content of “Generator Model” with the content of “Excitation Control” in a single column called “Generator and Excitation Model(s)”. Also, to be consistent, rename the “Governor Control” column by “Prime mover and Governor Model”. Most importantly, remove note 12. Finally, create a new column for “Synchronous condenser”, to avoid any confusion.

6.3 Excitation limiters

In Table 1.1 of Attachment 1, the requirement currently listed as:
“Model(s) representing enabled excitation limiters”
…should be relocated to the “Excitation Model(s)” column and to the new “Synchronous condenser” column. It should be a Model Verification only (no validation activity).
Justification: This is aligned with comment 6.1, excitation limiters being part of the excitation system.

6.4 Text standardization with R3

To improve the clarity and fluidity of the text, ensure alignment with the applicable facilities, and avoid redundancy with Requirement R4 regarding “changes”, it is recommended to revise section R2 as follows. The proposed text is based on the structure of R3, with suggestion to delete the use of "verified" (to solve the concern raised in the answer of question 2). Other modifications from R3 are shown below using bold (for additions).
“R2. For facilities identified under the Applicability sections **4.2.1, 4.2.2 and 4.2.3.1**, each 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 according to the requirements and processes developed by its Transmission Planner and Planning Coordinator in Requirement R1 Part **1.1 and according to Table 1.1 of Attachment 1**., within the timeframe specified in Attachment 2. The model(s) and accompanying information shall include at a minimum the following:”
Proposed subsections (to be developed further):
2.1 Synchronous generator/exciter requirements – Model Verification and Validation for the generator/exciter, Model Verification only for the excitation limiter(s)
2.2 Synchronous condenser/exciter requirements – Model Verification and Validation for the synchronous condenser/exciter, Model Verification only for the excitation limiter(s)
2.3 Prime mover/governor requirements – Model Verification and Validation
2.4 Protection system requirements – Model Verification only

7. Changes (Requirement R4) : To improve clarity and ensure that Model Verification and Validation requirements are applied appropriately, it is recommended that Note 11 be revised to:

- Identify changes separately for each major component (e.g., generator/exciter, prime mover/governor, protection system).
- Avoid triggering unnecessary Model Verification and Validation when changes do not affect the dynamic behavior of the component in question.

For example, the following item currently listed in Note 11:

“(b) Addition or replacement of protection systems that deploy under-voltage and over-voltage and/or under-frequency and over-frequency elements”

…should be clearly identified as applying only to the protection system, and not to the generator/exciter, synchronous condenser, or prime mover/governor models. Protection systems, while critical for system reliability, do not influence the inherent dynamic behavior of the generator, exciter, or governor systems. Therefore, their modification should not trigger a new Model Verification or Validation for those components.
Another example would be to remove “(c) plant digital control system addition or replacement” from Note 11, because the plant digital control system does not influence the dynamic characteristics of the generator/exciter, synchronous condenser/exciter or prime mover/governor.

8. Equivalent Unit Verification Condition (row 10 of Attachement 2) : Row 10 of Attachment 2 appears to allow the verification and validation of only one equivalent unit at a time for a multi-unit facility, potentially spreading the process over an unreasonably long period. For example, for a 10-unit plant, if a different equivalent unit was to be verified/validated at every 10 years, the last unit would be verified/validated in 100 years — an impractical and undesired outcome for reliability purposes.

Row 10 of Attachment 2 of MOD-026-2 should only apply during the initial verification of an applicable facility (row 1). For all the other cases, Model Verification and Validation should be performed for each single facility/unit. This was the intente in MOD-026-1 and MOD-027-1.

For this reason, perform the following change at column “Required Action” of row 10 as follows. Modifications are indicated using bold for additions. We recommend deleting " Verify the model(s) of a different equivalent unit during each 10-year verification period" and adding " **Applies to Row 1 only.**”

9. Current average net capacity factor (Row 13 of Attachment 2)

9.1 Exemption for R4 : If the current average net capacity factor over the most recent 3 years is below 5%, this means that the unit is rarely operated. The purpose of Row 13 of Attachment 2 is to reduce the compliance burden for such infrequently used units.

To align with this intent, Row 13 should also apply when changes are made to the in-service equipment. There is no practical benefit in deploying efforts to validate the model of a unit that is not in operation.

Proposed change: In the “Modeling Condition” column of Row 13, revise the text as follows. Delete R4 (In Requirement R2 or Requirement R3 periodicity exemption of Row 3, does not exempte obligation under Requirement R4 or R6)

9.2 Periodicity : Row 13 of Attachment 2 introduces a new requirement for periodicity, mandating that the written statement now be submitted to the Transmission Planner on an annual basis. This represents a significant change from the 10-year periodicity specified in MOD-026-1 and MOD-027-1. While performing this activity annually is reasonable, we recommend allowing a 13-month interval instead of a strict 12-month period. This additional month provides valuable flexibility to maintain a consistent calendar date each year. Without it, the compliance deadline would gradually shift earlier each year, creating unnecessary administrative burden.

10. Proposed new line at Attachment 2: Units out of service for repair: A new row should be added to Attachment 2 to address the case of units that are out of service due to long-term repairs, whether planned or unplanned. Units undergoing such repairs cannot be validated according to the periodicity specified in Row 3, as they are not operational during that time.

To accommodate this situation, an additional year should be granted for model validation, starting from the date the unit returns to service. This new row should be linked to Row 7 ("Plan to verify the model") to ensure consistency in the validation process.

Likes 0	
Dislikes 0	

Response

1. R1-1.1.1.
The DT considers the review of limiter and protection structures, along with their parameter values, to be an integral part of the Model Verification process. This review ensures that the models accurately represent the associated equipment or facility. Rather than requiring the Generator Owner (GO) to provide models and verify all limiter and protection functions listed, Requirement 1, the R1-1.1.1 narrows the compliance obligation to only a subset of functions specified in Attachment 1, as determined necessary by the applicable Transmission Planner (TP).

2. R1-1.2
Requirements R1-1.2, R1-1.2.1, and R1-1.2.2 apply exclusively to legacy facilities. These provisions narrow the EMT (Electromagnetic Transient) modeling compliance obligations to only those legacy facilities identified by the applicable Transmission Planner (TP).
For new facilities, EMT modeling requirements are addressed through the interconnection process under FAC-001 and FAC-002 standards. These standards do not apply to legacy facilities, and therefore, there is no conflict.

3. R3.3
Requirement R3-3.3 now 3.4 has been rephrased to clarify that the facility's EMT model must include all associated parameters representing the applicable components. These include inverter-based resource (IBR) units, collector systems, auxiliary control devices, power plant controllers, generator step-up transformers, and main transformers. Additionally, the model must incorporate all enabled protection and limiter functions.

4. Note 1:

The DT has moved Note 1 to a footnote, and has renumbered the frequencies to the most up to date numbers. The DT could not create the mechanism as suggested so the new footnote has been updated but must stay.

Row 14
Row 14 of attachment 2 is removed.

Comment 5.
Sections A.4.2.1 and A.4.2.2 have been revised to clarify applicability by explicitly limiting their applicability to synchronous generating facilities. This was achieved by adding the term "synchronous" to both sections, thereby narrowing the requirements and ensuring they do not apply to inverter-based resources (IBRs).

Comment 6.
6.1
(DT) believes that the inclusion of Attachment 1 has significantly improved the clarity and organization of the positive sequence model requirements for applicable facilities. By consolidating these requirements into a single, concise, and well-structured format, the SDT has reduced ambiguity and improved usability.
Independent compliance for each major component—such as the generator/plant, Volt/VAR control, frequency/governor control, and limiter and protection functions—has been achieved through the design of Tables 1.1 and 1.2. Each major component is assigned a dedicated column, clearly outlining the specific modeling, Model Validation, and Model Verification requirements applicable to that component.

6.2
The DT agrees and revised Note 12 by removing the reference to governor model validation.

6.3
The DT see the need to assign a dedicated column for applicable enabled Limiting and Protective Functions and not including it to the exciter and governor column. This approach ensures that such model(s) are only provided when specifically requested by the Transmission Planner (TP) and are subject solely to Model Verification, not Model Validation.
To clarify this distinction, a Note has been added, stating that for the “Additional Limiting and Protective Functions” column, the Generator Owner (GO) or Transmission Owner (TO) is only required to perform Model Verification.

6.4

The term “verified” has been removed from Requirements R2, R3, and R4. These requirements were revised to enhance clarity, improve the flow of the language, and ensure consistent alignment across the related requirements. The modifications aim to better reflect the intended compliance expectations.

Comment 7:
Note 11 has been removed from the draft and R4 has been modified to clarify the types of triggering changes, specifically changes that alter the dynamic response characteristic.

Comment 8:
Row 10 of Attachment 2 has been carried over from Row 5 of Attachment 1 in the existing MOD-026-1 and MOD-027-1 standards. The DT does not identify any reliability gap in maintaining the same Model Validation and Model Verification requirements for equivalent units within the same plant over each 10-year period.
Any potential reliability concerns are addressed in Requirement R6, which allows the Transmission Planner (TP) to request additional Model Validation and Model Verification for any plant or unit—including equivalent units—if model deficiencies are identified. For example, if the response of an equivalent unit to a system disturbance differs from that of the tested equivalent unit, the TP may initiate further validation or verification as needed.

Comment 9:
9.1 The DT does not believe that infrequently used units should be exempt from requirement R4. Changes that alter the dynamic response characteristic should be modeled to represent most up-to-date version of the BES regardless of frequency of use.
9.2 The 10-year periodicity requirement of MOD-026-1 and MOD-027-1 still applies to subsequent model validation and verification, shown in Attachment 2, Row 3. The annual submission applies to the maintenance of the R2 and R3 exemption status based a rolling annual average net capacity factor. If a facility no longer qualifies for the exemption, model verification must be performed within 365 days. Incorporating a 13-month interval instead of an annual notification may introduce confusion or misalignment. An annual requirement still permits submission on a consistent calendar day each year.

Comment 10:
DT that this concern has already been addressed in Row 12 of Attachment 2 since the net capacity factor of a unit in long-term outage would be 0%.
9.1 The DT does not believe that infrequently used units should be exempt from requirement R4. Changes that alter the dynamic response characteristic should be modeled to represent most up-to-date version of the BES regardless of frequency of use.

9.2 The 10-year periodicity requirement of MOD-026-1 and MOD-027-1 still applies to subsequent model validation and verification, shown in Attachment 2, Row 3. The annual submission applies to the maintenance of the R2 and R3 exemption status based a rolling annual average net capacity factor. If a facility no longer qualifies for the exemption, model verification must be performed within 365 days. Incorporating a 13-month interval instead of an annual notification may introduce confusion or misalignment. An annual requirement still permits submission on a consistent calendar day each year.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Southern Company supports EEI comments.

In addition, Southern Company recommends the following:

- TP and PC should identify which facilities, both BES and non-BES alike, that require an EMT model. It is an unjustified burden and cost on the GO to require an EMT model be produced with every IBR facility without justification.
- For Footnote 1: Use the ”Commercial Operations Date (COD)” in place of “in-service” date.
- Section 4.2.6 implies that 20 different GOs each with 1 MVA inverters connected at a common POI > 60 kV as being in scope. The Technical Rational tries to make amends, but at the time of this comment period, this is a future intention and does not sufficiently decerning the intent of applicability:

Pg.3 of Technical Rationale:
The Drafting Team (DT) added language in the Facilities section numbers 4.2.5 and 4.2.6 which cover IBRs that are registered and unregistered devices. These items are carried over from FERC Order No. 901 Milestone 2 projects which ensure these standards not only apply to the BES but also the Bulk Power System (BPS). **These Facilities section items are "*due to change" once* the updated definitions of Generator Owner and Generator Operator, which include BES and BPS entities as Category 1 and Category 2, respectively, are approved for inclusion in the NERC Glossary of Terms.**

This example serves to reiterate and exemplify that the speed at which FERC expects these standards to be ratified out-paces the due diligence and development processes needed by industry for meaningful effective policy development.

Combining MOD-026-1 and MOD-027-1 into a single standard brings complexity on the GO, TO, PC and TP by having multiple due dates for different model validations embedded in the same standard. Rarely, if ever, are field step tests conducted for AVR model and PFR model validation. These dates do not align and will never align for synchronous machines. For IBR, there should be no problems. Delineation and complication of what model validation is being submitted to the PC and TP is now requiring a descriptive narration and may lead to confusion. AVR and PFR model validations are totally separate in purpose and use and should stay that way.

Likes 0	
Dislikes 0	
Response	

The purpose of requiring EMT modeling of IBRs (also FACTS and HVDC) is to be able to effectively validate the large disturbance behavior of the positive sequence modeling. It is the nature of IBRs (and FACTS and HVDC) that their large disturbance behavior cannot reliably be extrapolated from small disturbance field testing. Discretion is given to TPs regarding the need for EMT modeling of legacy projects only because it is recognized that owners may be unable to obtain it or it may be very costly to obtain it. There is also an exemption clause (in the Implementation Plan) in case the GO or TO cannot obtain EMT modeling from their OEM even though a TP may request it.
The change has been adopted for the second bullet point.

Bullet point three: This language is needed until and after the Category 2 GO language passes. This language is from Milestone 2 Order 901 projects to cover all respective entities to fulfill Order 901. Regarding Applicability 4.2.6, the DT has attempted to clarify the intent in the Technical Rationale as noted. While the hypothetical presented may be in scope, the situation is highly unusual. Further, such a facility may still require a model regardless of ownership. Consider if such a facility had 20 GOs each owning 4 MVA inverters. The DT would also point to the modifications in Part 1.2.1 which would allow the TP/PC to specify if no EMT model is required for such a facility. While this may not alleviate the burden of providing positive-sequence models, it may allow the TP/PC to reduce the burden on generators with unusual configurations on their system.

The MOD-026-2 does not require the tests to be completed all at the same time.
The purpose of requiring EMT modeling of IBRs (also FACTS and HVDC) is to be able to effectively validate the large disturbance behavior of the positive sequence modeling. It is the nature of IBRs (and FACTS and HVDC) that their large disturbance behavior cannot reliably be extrapolated from small disturbance field testing. Discretion is given to TPs regarding the need for EMT modeling of legacy projects only because it is recognized that owners may be unable to obtain it or it may be very costly to obtain it. There is also an exemption clause [in the Implementation Plan] in case the GO or TO cannot obtain EMT modeling from their OEM even though a TP may request it.

Richard Vendetti - NextEra Energy - 5	
Answer	
Document Name	
Comment	

Nextera further supports comments submited by EEI and SRC	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to SRC and EEI's comments.	
David Vickers - Vistra Energy - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Alison MacKellar - Constellation - 5,6	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
Thank you for the response.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Clarification is needed that additional limiting and protective functions also documented in PRC standards do not need to be validated per MOD-026-2. PRC standards require GOs to demonstrate coordination through documentation. This method has proven success and should not be rolled into MOD-026. Protection demonstrated in PRC standards being rolled into MOD-026 will have significant resource impacts as well as MOD-026 testing occurring more frequently.	
Likes 0	
Dislikes 0	
Response	
Attachment 1, Tables 1.1 and 1.2 only mention inclusion of models of limiting or protective functions and does not include validation. The DT will review language and add clarity to ensure there is no misinterpretation.	
Carver Powers - Utility Services, Inc. - 4	
Answer	
Document Name	
Comment	
USV suggests that when the TP change their acceptable criteria for a model, the entity responsible for providing the data should have a true up period (Recommendation 24 months) to meet the new criteria. This way if an entity is in the 9th year of their cycle and the criteria changes, they are not required to comply in less than 12 months to the new criteria. This period may also be warranted when there is a change to equipment at a substation instead of the 180 days the standard gives.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response and the suggested revisions. Based on the implementation timelines of previous versions of the standard (MOD-026-1 and MOD-027-1), a 24-month timeline would be too long to incorporate into the new draft. To address this, the language in the Implementation Plan will be reviewed to ensure fringe cases are avoided under the new standard.
The proposed implementation provides a phased approach:

- **Requirement R1** becomes effective **12 months after the effective date**;
- **Requirements R2 through R7** become effective 36 **months after the effective date**.

This structure is intended to give entities sufficient time to prepare and transition to the new Requirements while maintaining alignment with precedent and ensuring clarity and enforceability.

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

BPA reiterates and expands on its response to question 1: If the rationale for requirement R3 does not make any mention of HVDC or FACTS, only IBR's, then HVDC and FACTS equipment should not be required to comply with requirement R3.

BPA believes extra, unnecessary overhead of work will be created by the 'Facility' section in Table 1.2. An HVDC system could have multiple control system manufactures. HVDC control & protection systems do not have a model number. There's an abundance of software and firmware at an HVDC facility, which is being tracked for NERC CIP requirements and would provide little benefit for modeling purposes. Control and protection system code, which could affect the operation, could change without the software or firmware version being changed. The rationale for adding HVDC to Attachment 1, Table 1.2 is not based on a solid foundation, as it references BES Inclusion I4. I4's definition is "Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above". BPA does not believe HVDC should be included as an IBR.

Likes 0	
Dislikes 0	

Response

The DT will add language into the Technical Rationale about HVDC and FACTS into Requirements R3 rationale. The DT believes that FACTs and LCC devices have a significant impact on the BPS. They have a possibility of interacting between them and other generating resources. The DT sees a reliability need to include this despite FERC Order No. 901 explicitly stating to include these devices.

Isidoro Behar - Long Island Power Authority - 1	
Answer	
Document Name	
Comment	

** R1, R2, and R3 – as they relate to Model Validation

Req 1 specifically mentions “model verification requirements and processes“.

Footnotes 4 and 5 mention “Model Validation activities”.

Concern: should there be explicit mention of “model validation” requirements & processes in Req 1? Responsibilities and/or specific requirements for “model validation” are not clear and should be identified in the main requirement language. Footnotes 4 and 5 mention model validation activities, and there should be associated requirement language added (to Req 1, and possibly Reqs 2 and 3) to clarify such model validation activities to facilitate entity compliance.

** Requirement 1, sub requirement 1.3, Footnote 3

Footnote 3 is somewhat confusing. We recommend to edit Footnote 3 as follows:

“Model submittal requirements needed by the Transmission Planner may include, but are not limited to, required data files and inclusions *required as part of the model documentation*.” (REMOVE = needed in the model report.)

Additionally, if a “model report” is required, should a specific requirement be created for this purpose?

** Question to the SDT for clarification:

If a legacy facility is identified (based on the jointly develop dynamic model verification requirements and processes under R1) as requiring an electromagnetic transient (EMT) model(s) under Requirement R3, and that legacy facility does not have an available EMT model, what is the timeframe for compliance with R3, or does the R3 exemption (Attachment 2, row 14) apply?

It is recommended that this scenario be clarified.

** Requirements 2 and 3 – editorial comment

The basic premise and specific requirements that are part of Requirement 2 (positive sequence models) and Requirement 3 (EMT models) are similar in nature. However, it appears that these two requirements may have been drafted by different teams, and as such some of the language is confusing and/or not totally consistent. This perceived inconsistency in language creates unnecessary confusion and potentially hinders the ability of an entity to ensure compliance. For example, both requirements mention the provision of models and both requirements refer to the "Periodicity table in Attachment 2" (or as alternatively specified in Req 3 – "timeframe specified in Attachment 2"). It is recommended that the SDT review the language in both Requirements 2 and 3 to ensure consistent language is used throughout for the same types of "requirements" and for common references (such as Attachment 2), and to ensure a common structure / layout is used for the main requirements and sub-requirements.	
Likes 0	
Dislikes 0	
Response	
This wording has been removed to add clarity. The word verification has been removed, as Requirement R1 is meant to have dynamic model submission requirement and processes, no Model Validation nor Model Verification requirements as they are listed in Requirements R2 and R3. Footnotes 4, and 5 have been removed. The DT has changed footnote 3 to conform with the provided language. The language in row 1 of attachment 2 allows for 365 calendar days for new applicable facility and equipment. Regarding legacy facilities required to have an EMT model, the EMT model would be required at the time of the next submission due under MOD-026-1 or MOD-027-1. More details are included in the implementation plan. The exclusion for EMT models only applies when the OEM(s) for the facility equipment are no longer operating or do not have an EMT model available. With new edits to Requirement R3, Requirement R2 conforms with how Requirement R3 is written. This suggestion has been accepted.	
Thomas Foltz - AEP - 3,5,6	
Answer	
Document Name	
Comment	

R3.6 requires that the verified model(s) and accompanying information provided will include "Documentation comparing large signal disturbance response of the facility positive sequence dynamic model(s) provided in Requirement R2 to the response of the facility EMT model." While insight is provided in the Technical Rationale regarding what a large signal disturbance "is typically," the information provided may not be sufficiently detailed, and could lead to an inconsistent interpretation and application of the phrase. AEP suggests that consideration be given to provide additional clarity in the Technical Rationale, and perhaps in the standard as well.

While AEP acknowledges the desire and reliability need for MOD-026 version 2, we do not agree with the language of Requirement R1 subpart 1.1.1. leaving it to the discretion of the named functional entities to determine whether limiting and protective functions are required to be represented in the models for synchronous generators. We believe this is beyond the scope and intention of the SARs and the Inverter Based Resources Task Force (IBRTF), respectively. The language allows for the potential that undue burden may be placed on the Generator Owners to provide additional limiter function and protection model data. This may be unnecessary and could likely result in circumstances where Planning Coordinators and/or Transmission Planners may reject previously accepted verified models of synchronous machines. These long standing and well-proven models using years of generator, excitation, compensator, power system stabilizer, turbine-governor, and load-controller data utilized in planning studies might be determined to be unusable simply due to limiter or relay model acceptance criteria that is poorly defined, extremely rigid, or not fully understood. This would warrant a significant expenditure of time and resources to comply with and is not likely to achieve any meaningful contributions in improving the reliability of the BES.

AEP provides below three previously-provided justifications for not including of models representing Protection Systems of synchronous generating units as stated in Attachment One's Table 1.1, column four…

1. MOD-032 allows the TP and PC to request protection system data and modeling if it is deemed necessary. MOD-026 is supposed to be a model verification/validation standard. It should not be expanded into a data collection standard and thereby cause compliance duplication with MOD-032. 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. Attachment One's Table 1.1, column four 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 historical disturbance event tripping and runback, the specified protection functions of synchronous generation have 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.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, new language has been added to try to have the TP define what a large signal disturbance is. The language has been modified in Requirement R1 Part 1.1 to remove references to MOD-032 and Part 1.1.1 has been modified according. Column four in Table 1.1 is included so the TP can pick and choose which additional protections are needed to be provided to them. These are to ensure that the GO and TO know what is expected, and to further the reliability.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
For model validation the minimum data sampling resolution should be included in Attachment 1 for staged test or recorded system disturbance data. MH asks the DT to consider adding language to the MOD-026-2 standard to address generating units on a long-term outage (and do not have an equivalent unit) that cannot have staged testing for model validation within the specified periodicity. MH suggests similar language to MOD-025 where the GO has 365 calendar days to provide a model verification and validation after the unit has been returned to service.	
Likes 0	
Dislikes 0	
Response	
The standard is not intended to provide minimum Model Validation criteria, it is left to the applicable TP to provide this criteria, if required. Additionally, the minimum data sampling resolution of the recorded system disturbance data is specified in PRC-002 and PRC-028. The model dynamic simulation time step is part of the TP dynamic simulation methodology (In general, ¼ cycle). DT believes that concerns regarding generating units on long-term outage (and without an equivalent unit) that cannot undergo staged testing for model validation within the specified periodicity are already addressed in Row 12 of Attachment 2, as the net capacity factor of a unit in long-term outage would be 0%.	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	

Reclamation does not agree with heavily modifying a base standard meant for in the method that this has been done, especially with non-defining attributes in the requirements between IBR and non-IBR industry. It is recommended that the IBR resources should have their own stand-alone modeling.
 	
Inclusion of non-BES IBR resources should not be considered as these resources do not fall under the compliance oversight of NERC. This standard is vague and not properly laid out to identify requirements between IBR and non-IBR resources.
 	
If this standard modification will proceed in this format, Reclamation recommends the following:
 	
• Include loss-of-field and out-of-step protective elements to the examples list in footer note 9 on page 8 of 36 of the redline draft.
• Attachment 1 – Applicability:
    o Item 1 page 26 of 36 of the redline: The scope of model(s) representing enabled excitation limiters should be isolated to the limiters that are enabled during online operations only.
    o Item 2 page 26 of 36 of the redline: It is unclear of the intent of this requirement and clarification is required. If it is intended that only the underline protective elements will need to be model, then it is somewhat reasonable. However, if the intent is that all protections that trip the generator require modeling then this is very concerning. Many of the protections will not be able to get modeled.	

Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The directive P143 of FERC Order No. 901 assigned to this project has specified that "…NERC to establish a standard uniform model verification process. A uniform model verification process will ensure that all entities use the same set of minimum requirements to verify that all generation resource (i.e., synchronous and non-synchronous) models are complete and that the models accurately represent the dynamic behavior…" With this directive and the DT's previous efforts on the project, the DT felt that MOD-027-1 and MOD-026-1 should be combined and applied to both synchronous and non-synchronous generating facilities and equipment. Thank you for the edit suggestions, the example list can be added to the Technical Rationale. For Attachment 1: the edits to the table and removal of the paragraphs into the body of the language of Requirement R2 should help clarify these concerns.	
Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	

Retroactivity, for creation of an EMT model for legacy facilities, places the need for significant additional deliverables from the OEMs. This will place complex challenges to complete this requirement.

It is our request that this Standard NOT be applied retroactively. It will require significant financial investment by the Generator Owner for legacy facilities that are through the majority of the anticipated project lifespan.

One of our OEMs requested near $750,000 for development of a PSCAD model for the generator at a facility that declared COD in 2009 as such a model does not currently exist. Development of this model would require significant coordination and effort between the converter manufacturer and the generator manufacturer. The need for the creation of models for older facilities will take focus of the OEM away from developing new capabilities to meet high-priority developing Standards (for example PRC-028-1 and IEEE2800).

Likes 0	
Dislikes 0	

Response

Thank you for the comment. Exclusion language has been added to Requirement R3, allowing certain legacy facilities to be conditionally exempt from EMT testing. The Drafting Team (DT) believes EMT is essential—when feasible—for fully validating IBR models, as dynamic modeling does not always produce the same results as EMT. These differences are evident in the Odessa reports and other NERC reports. To ensure the reliability of the Bulk Power System (BPS), the team will not be removing Requirement R3 entirely. Instead, exclusion language has been added to balance the need for thorough validation with practical implementation considerations.

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

Answer	
Document Name	

Comment

Recommend incorporating the following EEI R4 correction:

Connect the update to any change that affects the model rather than referring to the dynamic response. Some GO/TOs may not be aware that a change they made alters the response. If the setting is in the model, then a change in the setting should require a model update. EEI suggests the following:

• R4. Each Generator Owner or Transmission Owner, upon making a hardware, software, firmware, control mode, or setting change(s) to any in-service equipment specified in Requirement R2 or Requirement R3 that [delete] model, …

Note: EEI bullet 2 not included.

Correct MOD-026-2 Attachment 2 Periodicity Table: Table does not include Row 5 - Revise table row numbering and standard text to reflect correction.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the response to EEI’s comment, and conforming changes made to the MOD-026-2 standard.	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	
Document Name	
Comment	
See comments submitted by Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, please see the response to EEI’s comment, and conforming changes made to the MOD-026-2 standard.	
Timothy Singh - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
In Attachment 1, regarding additional steps when performing modeling testing, this added criteria will cause added expense to utilities by virtue of adding criteria not previously required, possible additional software to validate testing, training personnel to perform validation.	

There is currently no requirement in the NERC ROP for a GO to have a TP. As identified in NERC IBR conference on January 15/16, many GOs do not have a TP and in the west, TPs do not provide these services for interconnected GOs. TPs will have to increase staff, in order to accommodate the increased model validation that is needing to be performed. TPs have no ability be able to enforce cooperation from the GO when dealing with models when this relationship does not exist.

SRP recommends having a phased approach requiring each Generator Owner and Transmission Owner to have a verified percentage of its applicable units by certain timeframes, as done with the Implementation Plan for Project 2007-09 Generator Verification.

Likes 0	
Dislikes 0	

Response

Thank you for the comment, the DT believes that Attachment 1 is consistent with directives from FERC in Order 901 regarding requirements for Model Validation and Model Verification and the respective roles of facility owners, planners, and operators. NERC reliability standards requirements have compliance obligations and requires coordination between various entities to ensure reliability as well as establishing relationships between entities as required where previously none may have been existed. The DT believes that the periodicity table (Attachment 2) in the draft standard ensures model verification and validation for all applicable facilities in a timely manner and as such a phased approach is not required.

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI provides the following comments for consideration:

· Throughout the document “verified model” should be replaced with the defined terms - Model Verification and Model Validation.

· The periodicity in Attachment 2 should be included in the requirements.

· **Applicability:**

o 4.2.7 Recommend deleting this bullet because it could create confusion based on 4.2.6 and is duplicative.

· **Requirement 1**

o Use of uncapitalized “model verification” could be confusing given the defined term. EEI suggests the following:

• Each Transmission Planner and its Planning Coordinator shall jointly develop dynamic model**ing** requirements and processes. The dynamic model requirements…

o The relationship of R1.3 to R1.1 and R1.2 is confusing because R1.1 and R1.2 must be part of the acceptance criteria required in R1.3. There are multiple ways that the drafting team can address this including re-ordering the requirement parts to make the current 1.1 and 1.2 sub-requirements of the current 1.3. The relationship between 1.1-1.3 should be clarified.

· **Requirement 2**

o R2 should reference Model Verification and Model Validation rather than using “verified model”. EEI suggests the following:

• R2. Each Generator Owner or Transmission Owner shall provide **to its Transmission Planner: models that have documented Model Verification and Model Validation, documentation** of Model Verification of a positive sequence dynamic model(s) with associated parameters, and any information pertaining to changes to the model(s) or its parameters. The Generation Owner or Transmission Owner shall include documentation that:

o R2.2 should be more aligned with the Model Verification definition. EEI suggests the following:

o R2.2 Verifies that the model(s) **structure and parameter values** represent the in-service equipment **or** facility **design and setting**, for those parameters that can be confirmed by the Generator Owner or Transmission Owner.

· **Requirement 3**

o Conducting the two staged tests could degrade reliability, operational flexibility, and market operation of the real time system when they are conducted. Further, the FERC Directive does not seem to require the level of detail documented in Requirement R3 Parts 3.1-3.6. While EEI agrees that the information included is valuable, it would be more appropriate to include in a technical rationale and/or guidance document. We suggest deleting Requirement R3 Parts 3.1-3.6 and moving the information to guidance.

· **Requirement 4**

o Recommend connecting the update to changes that affect the model as described in Footnote 11, rather than referring to the dynamic response in the requirement language. The footnote already includes dynamic response. Some GO/TOs may not be aware that a change they made alters the response. If the setting is in the model, then a change in the setting should require a model update. EEI suggests the following:

• R4. Each Generator Owner or Transmission Owner, upon making a hardware, software, firmware, control mode, or setting change(s) to any in-service equipment specified in Requirement R2 or Requirement R3 that alters the **model**,11…

o Providing a “plan” is not sufficient. A timeline should be included. EEI suggests the following:

• A plan, **including the timeline,** to provide the verified model(s) and associated information in accordance with Requirement R2 or Requirement R3.

· **Requirement 6**

o The option to provide a “plan” is not satisfactory. A timeline should be placed on the correction. EEI suggests the following:

• A plan, **including the timeline,** to submit the verified model and accompanying information in accordance with Requirement R2 and Requirement R3

o The third option appears redundant with the first option. Consider removing it.

· **Attachment 2**

o For facilities that require EMT models, both PSPD and EMT models should be delayed such that they can be submitted together.

o **Row 2** The term “commissioning date” is undefined and unclear. EEI suggests the following:

• Transmit the verified model and accompanying information to its Transmission Planner within 365 calendar days after commissioning.

o **Row 3** Consider only including the “most recently approved submittal” rather than include the confusing 2nd paragraph.

• “verified model” should be replaced with Model Verification and Model Validation

o **Row 4** EEI suggests removing this row and placing the content in the Technical Rationale document. If the drafting team chooses to keep this, it will require revision because it appears to conflict with the information in Table 1.

o **Row 5** is missing.

o **Row 6** The timeline should be included in Requirement R4 and “verified model” should be removed and replaced with Model Verification and Model Validation.

o **Row 7** should be removed, and the timeline included in Requirement R4.

o **Row 8** The timeline should be included in the Requirement to allow all the expectations of the requirement to be understood in one location.

o **Row 9** is inconsistent with row 6. It is unclear while a failed model under R6 should have less time for correction than a model that receives a setting change. EEI suggests the following:

o Provide a written response to its Transmission Planner within **180** calendar days

o **Row 10** is not entirely a timing requirement, it is setting conditions that allow for the model of one unit to be used for another. Should this be in the requirement language?

• “Verified model” should be replaced with Model Verification and Model Validation o **Row 13** should this be merged with row 3 and explained as an exemption?

o **Row 14** is not a timing requirement. This is directly related to R1.2.1. Row 14 should be addressed in the Standard. EEI suggests the following:

• **R3.7 Document in a declaration to its Transmission Planner that an EMT model is precluded for one of the following: the commissioning of the applicable legacy facility (before the effective date of MOD-026-2); OR The original equipment manufacturer (OEM) is no longer doing business in North America; OR The OEM no longer supports model(s) for in-service equipment at the Facility.**

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Comment 1: The “verified model” has been replaced by “The updated model meeting Requirement R2, Parts 2.1 through 2.3 or Requirement R3 Parts 3.1 through 3.6”

Comment # 2: The drafting team has incorporated timelines directly within the language of Requirements 4, 5, and 6 where appropriate. However, to maintain clarity and avoid overly lengthy or repetitive requirement statements, timelines for R2 and R3 requirements were instead consolidated in Attachment 2. This approach was intended to strike a balance between readability and completeness.

4.2.7 was removed from applicability section.

R1:

The requirement language was changed to "shall jointly develop dynamic model requirements"

The current structure is intentional, as 1.1 and 1.2 define the specific model content and requirements applicable to various facility types, while 1.3 separately outlines the acceptance criteria to be used by the Transmission Planner to evaluate those models once submitted as stated under R5.

R2

The “verified model” was removed and replaced by “documentation of Model Verification”

To ensure alignment with the Model Verification definition we included the need to provide documentation of Model Verification and added sub requirement 2.2.1

R3:
The staged tests of Requirement R3 Part 3.4 and 3.5 are the same as the field step tests that are typically done under the presently enforceable MOD-026 and MOD-027 standards. These are the same staged tests referred to in Attachment 1, Tables 1.1 and 1.2, columns 2 and 3. R3.4 and R3.5 do not add more staged testing, they only require Model Validation of the EMT model from the same staged tests referred to in the Attachment 1 tables. The purpose of R3 has to do with the original SAR authorizing Project 2020-06. It is not driven by any 901 directives. The EMT model requirement has been present from the first draft of MOD-026-2 and is the means, per R3.6 (and after the EMT model has itself been verified and validated through R3.1-R3.5), by which large disturbance behavior of IBR modeling is validated. The EMT model required of IBR projects may be thought of as a substitute for staging faults and other large disturbance tests on the real system, which is obviously not in the interest of real-time reliability.

R4:
The DT believes that dynamic response change wording should remain as that this wording is making it recursive. The word model does not articulate the necessary details that effect the model. Also, note 11 was removed.

The need to provide “plan is removed, and the timeline is added to the requirement “within 180 calendar days or as mutually agreed upon with the Transmission Planner,”

R6:
The need to provide “plan is removed, and the timeline is added to the requirement “within 90 calendar days after receiving a notification of denial under Requirement R5, or within 180 calendar days or as mutually agreed upon with the Transmission Planner, after receiving a request,”

The first option and the third option were modified to remove any redundant with the first option.

Attachment 2:

Row 2
“Commissioning date” has been replaced with “commercial operation date.”
Requirement for the planner to act within 365 calendar days of the commercial operation date.

Row 3
The second paragraph has been removed.
The term “verified model” has been replaced with:
“Model meeting Requirement R2 Parts 2.1 through 2.3 or Requirement R3 Parts 3.1 through 3.6.”
Row 4
Has been modified to better align with the original wording from Row 3 in MOD-027-1’s attachment.
Row 5
Rows have been renumbered to include Row 5.
Row 6
Row 6 has been removed from the attachment.
The associated timeline has been incorporated into Requirement R4.
The term “verified model” has been replaced with:
“Model meeting Requirement R2 Parts 2.1 through 2.3 or Requirement R3 Parts 3.1 through 3.6.”
Rows 7–9
These rows have been removed from the attachment.
Their respective timelines have been incorporated into Requirements R4, R5, and R6.
Row 10
The DT considers this row to contain periodic information, appropriate for Attachment 2.
It addresses periodic testing of subsequent equivalent units.
The term “verified model” has been replaced with:
“Model meeting Requirement R2 Parts 2.1 through 2.3 or Requirement R3 Parts 3.1 through 3.6.”
Row 13 (now Row 12)
The DT recommends retaining this row.
Row 3 addresses Subsequent Model Validation and Verification for applicable facilities.
Row 12 provides exemptions for initial or subsequent Model Validation and Verification.
Row 14
Row 14 has been moved to Requirement R3, specifically in the body of Requirment R3 and in the IP general considerations.

Scott Thompson - TXNM Energy - 1,3

Answer	
Document Name	
Comment	

TXNM energy is in agreement with the following statements from EEI, and offer additional comments of our own. Throughout the document “verified model” should be replaced with the defined terms - Model Verification and Model Validation. The periodicity in Attachment 2 should be included in the requirements. Applicability: 4.2.7 Recommend deleting this bullet because it could create confusion based on 4.2.6 and is duplicative. Requirement 4: Providing a “plan” is not sufficient. A timeline should be included. EEI suggests the following: A plan, including the timeline, to provide the verified model(s) and associated information in accordance with Requirement R2 or Requirement R3 Requirement 6 The option to provide a “plan” is not satisfactory. A timeline should be placed on the correction. TXNM agrees with EEI in suggesting the following: A plan, including the timeline, to submit the verified model and accompanying information in accordance with Requirement R2 and Requirement R3 The third option appears redundant with the first option. Consider removing it. Attachment 2 Row 2 The term “commissioning date” is undefined and unclear. Entities use COD, Energization and others - define the term. Row 4 Removing this row and placing the content in the Technical Rationale document. If the drafting team chooses to keep this, it will require revision because it appears to conflict with the information in Table 1. R1.2.1 is in conflict with R3.7.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s responses to EEI’s comment. The DT has replaced the term of “verified model” with an expounded that clarifies a model that has undergone Model Validation and Model Verification activities. 4.2.7 has been removed as it is conflicting 4.2.6 in the Applicable facilities section. The timelines has been integrated in both Requirements R4 and R6. The DT has removed the commissioning date and has clarified and made it “COD.” Thank you for the suggestion this row will be left in but aligned with Table 1, the DT feels it is currently needed in the standard and does not belong in supporting documents like the technical rationale.	

There is no current Requirement R3, Part 3.7 in the initial draft, Potential Part 3.7 language has been added for legacy facility exemptions in the upcoming draft.	
Matt Lewis - Lower Colorado River Authority - 1,5	
Answer	
Document Name	
Comment	
LCRA believes models should have to conform with IEEE 2800_2	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The drafting team members involved in IEEE 2800 are working to ensure the standard is closely aligned with industry guidance and the provisions outlined in IEEE 2800.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC signed on to ACES comments. See ACES comments. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
See the DT's response to ACES comment.	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	

Answer	
Document Name	
Comment	
Xcel Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Steven Belle - Dominion - Dominion Virginia Power - 1,3, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy supports the additional comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	
Document Name	
Comment	
N/A	

Likes 0	
Dislikes 0	

Response

Thank you for the comment.

Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC

Answer	
Document Name	

Comment

R1-1.1.1. The goal of R1 is to "develop dynamic model verification requirements and processes".

R1-1.1.1 indicates: "Specify the limiting and protective functions listed within Table 1.1 that are required to be represented in the model" This is not a verification requirement or process; it is a modelling requirement which is not the intended goal of MOD-026.

R1-1.1.1. should be removed.

R1-1.2.-1.2.1. and 1.2.2. This should not be part of the "Verification and Validation" document. This is a modelling requirement. FAC-002-5 currently being developed by NERC project 2022-04 covers this by requiring TP/PC to develop and publish their EMT modelling requirements (in R1-1.1.). R1-1.2. should be removed.

R3-3.3. is a modeling requirement. It should be rephrased to verify this information is included to the model.

MOD-026, as proposed, covers verification and validation of models. It should also cover model quality assessment (the process of evaluating the plausibility, usability and numeric stability of a model based on a review of model documentation, data, and simulations), by the TP/PC to ensure the modelling requirements are met and the model can be used for the intended studies. MOD-026 seems like the standard who should cover this

Note 1 for should be removed. We suggest referencing the methodologies established to evaluate the models to indicate when a frequency event can be used to validate the model. (May also varies with the technology being tested)

In Row 14 of attachment 2, the modelling condition seems to apply only to R3 (EMT). However, the same reasoning can be applied to R2, with difficulties obtaining a phasor domain model. Will R2 be included in the exemption?

Likes 0	
Dislikes 0	

Response

The DT believes this should remain in the standard as this is needed for entities to know what to include with submitted models. The DT has modified Requirement R1 and its associated Parts to clarify the purpose is for TP/PCs to define the model requirements and any other requirements that submitted models and accompanying documentation must meet. This ensures GO/TOs understand the expectations for the models they submit, and allows GO/TOs to evaluate their models prior to submission.

The DT believes this should remain since the EMT model becomes a part of the validation process for the positive sequence dynamic model. In addition, if required, the EMT model also has to go through the verification process. In distinction from FAC-002, the models required under MOD-026-2 are required to have Model Verification and Model Validation processes performed. The FAC-002 models are submitted for reliability studies prior to the facility being built or a qualified changes being implemented, thus those models are not yet verified or validated.

The DT believes this part is necessary, as it should be included in the verified and validated model submission.

There was a lack of consensus among the DT members regarding model quality assessments. Discussions on this topic noted many challenges such as regional differences, determination of adequate levels of accuracy, challenges experienced by drafting team members on related topics, etc. However, the standard does not preclude TP/PCs from performing model quality assessments as part of their review. TP/PCs performing such assessments should make the model quality requirements available to GO/TOs under Requirement R1.

Note 1 was a carryover from the current MOD-027.

No Requirement R2 will not be included in the exemption. GOs are heavily reliant upon OEMs for EMT model development while alternatives exist for positive sequence dynamic models in lieu of OEM support. The standard does not require an OEM-developed, equipment-specific positive sequence model. Generic models may be reasonably parameterized without OEM support and utilized to fulfill MOD-026-2 Requirements.

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	

Comment

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

General Comments

- Throughout the document "verified model" should be replaced with the defined terms - Model Verification and Model Validation.
- The periodicity in Attachment 2 should be included in the requirements.
- Applicability:
- 4.2.7 Recommend deleting this bullet because it could create confusion based on 4.2.6 and is duplicative.

Requirement 1

- Use of uncapitalized "model verification" could be confusing given the defined term. EEI suggests the following:
    - Each Transmission Planner and its Planning Coordinator shall jointly develop dynamic modeling requirements and processes. The dynamic model requirements…
- The relationship of R1.3 to R1.1 and R1.2 is confusing because R1.1 and R1.2 must be part of the acceptance criteria required in R1.3. There are multiple ways that the drafting team can address this including re-ordering the requirement parts to make the current 1.1 and 1.2 sub-requirements of the current 1.3. The relationship between 1.1-1.3 should be clarified.

Requirement 2

- R2 should reference Model Verification and Model Validation rather than using "verified model". EEI suggests the following:
    - R2. Each Generator Owner or Transmission Owner shall provide to its Transmission Planner: models that have documented Model Verification and Model Validation, documentation of Model Verification of a positive sequence dynamic model(s) with associated parameters, and any information pertaining to changes to the model(s) or its parameters. The Generation Owner or Transmission Owner shall include documentation that:

Requirement 3

- Conducting the two staged tests could degrade reliability, operational flexibility, and market operation of the real time system when they are conducted. Further, the FERC Directive does not seem to require the level of detail documented in Requirement R3 Parts 3.1-3.6. While EEI agrees that the information included is valuable, it would be more appropriate to include in a technical rationale and/or guidance document. We suggest deleting Requirement R3 Parts 3.1-3.6 and moving the information to guidance.

Attachment 2

- For facilities that require EMT models, both PSPD and EMT models should be delayed such that they can be submitted together.
- **Row 3** Consider only including the “most recently approved submittal” rather than include the confusing 2nd paragraph.
  - “verified model” should be replaced with Model Verification and Model Validation
- **Row 6** The timeline should be included in Requirement R4 and “verified model” should be removed and replaced with Model Verification and Model Validation.
- **Row 7** should be removed, and the timeline included in Requirement R4.
- **Row 8** The timeline should be included in the Requirement to allow all the expectations of the requirement to be understood in one location.
- **Row 9** is inconsistent with row 6. It is unclear why a failed model under R6 should have less time for correction than a model that receives a setting change. EEI suggests the following:
- Provide a written response to its Transmission Planner within 180 calendar days
  - Row 10 is not entirely a timing requirement, it is setting conditions that allow for the model of one unit to be used for another. Should this be in the requirement language?
  - “Verified model” should be replaced with Model Verification and Model Validation

Likes 0	
Dislikes 0	

Response

Please see the DT’s response to EEI’s comment.

Hayden Maples - Evergy - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 5

Likes 0	
Dislikes 0	

Response

Please see the DT’s response to MRO NSRF and EEI’s comments.

Sing Tay - AES - Indianapolis Power and Light Co. - 3	
Answer	
Document Name	
Comment	
AES Indiana supports both MRO-NSRF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF and EEI's comments.	
Ijad Dewan - Hydro One Networks, Inc. - 1 - NPCC	
Answer	
Document Name	
Comment	
Legacy dynamic reactive resources should be exempt from requiring EMT models. Many of the SVCs currently in service are of older vintage, and we are concerned that we will not be able to obtain the EMT models. We would be able to support the draft if the EMT models for legacy dynamic reactive resources are exempted.	
Likes 0	
Dislikes 0	
Response	
With the new additional language in Requirement R3 the legacy facility and equipment with have an exemption with proper criteria and circumstances.	
Joseph Scott - Lower Colorado River Authority - 1,5	
Answer	
Document Name	

Comment	
LCRA believes models should have to conform with IEEE 2800_2.	
Likes 0	
Dislikes 0	
Response	
The DT members who are authors on IEEE 2800_2 are trying to align the standard with industry guidance as closely as possible and maintaining the reliability to the Bulk Power System.	
Karina Valencia - Oncor Electric Delivery - NA - Not Applicable - Texas RE	
Answer	
Document Name	
Comment	

· There is a lack of consistent capitalization of "Model Verification" and "Model Validation" throughout the standard. Please correct this if not intentional. If intentional, please explain what distinction is being made and why.

· It seems possible that Model Validation requirements developed by Planning Coordinators in MOD-033-3 could be different from Model Validation requirements developed for MOD-026-2. This could lead to confusion and inefficiencies if the criteria Transmission Planners use for MOD-026-2 reviews are in conflict with the criteria used by Planning Coordinators performing MOD-033-3 reviews. Has the SDT considered this possibility?

· There is a minor discrepancy between Requirement R1 and Measure M1.

o The requirement states:

§ "The dynamic model verification requirements and processes shall be made available to Generator Owner(s) and Transmission Owner(s) **by the Transmission Planner**"

o The measure states:

§ "**Each Transmission Planner and Planning Coordinator** shall have evidence demonstrating that the model verification requirements and processes were made available to the Generator Owner and Transmission Owner in accordance with Requirement R1"

o Is the intention to have the quoted portion of Requirement R1 above – "**by the Transmission Planner**" – include the Planning Coordinator?

Likes 0	
Dislikes 0	

Response

The DT has reviewed the standard and made changes to improve consistency while only using the officially defined terms of Model Validation and Model Verification. The team has also removed verified model and replaced it with a more understandable and clear term for a model that has undergone both Model Validation and Model Verification activities.

There will be no confliction has the TP and PC jointly develop the processes and information for the GOs and TOs in MOD-026-2. MOD-033-3 only has PC as their registered entities. MOD-033-3 only focuses on system level Model Validation while MOD-026-2 focuses on facility and equipment Model Validation.
The Requirement and Measure will be updated, to include the correct and both applicable entities.

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1,4,5

Answer	
Document Name	

Comment

To make things more straightforward and to avoid mixing different requirements, we suggest the SDT create a new, separate Standard just for MOD compliance with IBRs. Combining IBR requirements with the Standards that were originally made for synchronous machines has confused many and could make implementation more difficult.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The original mission of the drafting team was to develop MOD-026-2 by combining both MOD-026-1 and MOD-027-1. The team has remained committed to that objective, as it supports reliability and aligns with the intent of the original team members.

With the introduction of FERC Order 901, the team has added two separate tables in Attachment 1 to clearly outline the requirements for achieving Model Validation and Model Verification for each type of generation. Given the filing deadline in November 2025, the team will continue following this approach and apply similar processes for each generation type (P143) to fulfill the directive assigned to us.

Chris Wagner - Santee Cooper - 1,3,5,6, Group Name Santee Cooper

Answer	
Document Name	
Comment	
The Capacity Factor calculation requirements in MOD-026-1 and MOD-027-1 were valid for 10 years with instructions regarding recalculation at the end of 10 years and the deadline for model verification if the Capacity Factor increased to above 5%. Without this language, the Capacity Factor applicability calculation appears require recalculation annually using the most current 3 years. The Standard should specify how often the Capacity Factor is required to be recalculated to make it auditable.	
Likes 0	
Dislikes 0	
Response	
The DT has incorporated the previous version 1 standards drafting language into the new MOD-026-2 standard about the 10-year periodicity time for a facility or equipment. The Capacity factor is now in footnotes 14 and 15 in Attachment 2 Periodicity Table. These footnotes refer to the Net Capacity Factor equation to be used.	
Kimberly Turco - Constellation - 5,6	
Answer	
Document Name	
Comment	
Constellation has no additional comments.. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	

Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI's comment.	
Daniel Gacek - Exelon - 1,3, Group Name Exelon	
Answer	
Document Name	
Comment	
Exelon supports the proposed modifications to MOD-026, we also support the comments submitted by the EEI and encourage the drafting team to consider making the EEI suggested clarifications.	
Likes 0	
Dislikes 0	
Response	
Thank you for the support, please see the DT's response to EEI's comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	

Document Name	2020-06_Initial ballot Unofficial_Comment_Form_MOD-026-2_May_22_2025_ERCOT_Final.docx
Comment	

Comments on the Purpose statement:

If the “models” referenced in the Purpose statement are intended to be the models submitted in accordance with MOD-032, that link should be made more explicit within MOD-026-2. Otherwise, there are no requirements that ensure that these verified and validated models get incorporated into MOD-032 case-building processes. That link could be made by revising Requirement R2 (as proposed below) to require verification and validation of models submitted in accordance with MOD-032. Furthermore, the underlying purpose of the process should be model accuracy (which is a theme throughout FERC’s directives in Order No. 901). ERCOT proposes the following revised purpose statement to provide the necessary clarification:

To confirm that the dynamic models and associated parameters used to assess Bulk Electric System (BES) reliability **accurately** represent the in-service equipment of BPS facilities, including generating facilities, transmission-connected dynamic reactive resources, and high-voltage direct current (HVDC) systems.

Comments on the Facilities portion of the Applicability section:

Section 4.2.2

During drafting team meetings, it was suggested that Inclusion I2 of the BES definition does not include IBRs, but Inclusion I2 makes no specific reference to IBRs:

•I2 – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:

a) Gross individual nameplate rating greater than 20 MVA. Or,

b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.

Consequently, it appears that a wind or solar plant with an aggregate nameplate rating greater than 75 MVA could fall under Inclusion I2b. This potential overlap is significant because verification/validation requirements are specified based on these facility designations (see, e.g., Attachment 1).

Section 4.2.3

Inclusion I5 does not include a 20 MVA threshold, and it is unclear why facilities that are considered part of the BES according to the BES definition should potentially be excluded from verification/validation because of the 20 MVA threshold in section 4.2.3. This appears to create a potential loophole that could allow entities to circumvent verification and validation requirements by strategically sizing or modularizing their BES devices.

Section 4.2.7

Section 4.2.7 excludes facilities meeting an Exclusion of the BES definition; however, Exclusion E1b of the BES definition could certainly exclude facilities that meet the criteria in section 4.2.6:

• E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: . . .

b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

For example, a 70 MVA wind farm connected to a 115kV station through a single radial line would satisfy the E1b exclusion but would also meet section 4.2.6. As MOD-026-2 is currently written, it is not clear if MOD-026-2 would apply to such facilities (because of section 4.2.6) or exclude such facilities (because of section 4.2.7). ERCOT consequently recommends that section 4.2.7 be deleted to remove this ambiguity. If the drafting team elects to retain section 4.2.7, the Technical Rationale should be updated to address section 4.2.7 and the Applicability section of MOD-026-2 should be revised to clarify whether the standard applies to facilities that meet both section 4.2.6 and section 4.2.7.

Comments on Requirement R1:

Part 1.1

It is unclear why the model specifications already developed from MOD-032 need to also be included in the model verification requirements and processes in Requirement R1. Instead, Requirement R2 should apply to the model submitted in accordance with MOD-032, which would remove the need to duplicate MOD-032 specifications in Requirement R1. Part 1.1 should therefore be revised to read “Specification of the limiting and protective functions listed within Table 1.1 of Attachment 1 that are required to be represented in the model;” and subpart 1.1.1 should be deleted.

Part 1.3

The use of “criteria” could easily be interpreted by an auditor to mean quantitative criteria related to model accuracy. The P2800.2 team has struggled with this exact issue of how to evaluate accuracy and has ultimately concluded that accuracy evaluation is a matter of engineering judgment. MOD-026-2 should unambiguously adopt a similar position rather than implying that the PC/TP will be able to develop objective “criteria” to determine disposition under Requirement R5. Any validation should be deemed acceptable based on the engineering judgment of both the facility owner (prior to submission) and the TP (during evaluation of the submission). The Technical Rationale seems to suggest that the Part 1.3 reference to acceptance criteria was intended primarily to address model usability, but that intent is not at all clear in the draft requirement language for Part 1.3. Furthermore, if MOD-026-2 is revised as ERCOT proposes below, with Requirement R2 requiring verification and validation of models submitted in accordance with MOD-032, the models should already be usable based on the requirements of MOD-032. Thus, Part 1.3 is unnecessary and should be deleted in favor of ERCOT’s proposed modifications to Requirement R5.

Part 1.4

It is not clear that a “process” is really needed for Part 1.4, and ERCOT recommends that Part 1.4 be deleted because the required data exchange is covered by Requirements R2 and R3. Discussion during drafting team meetings indicates the drafting team appears to believe that Part 1.4 provides more flexibility for the PC/TP. However, Part 1.4 creates an unnecessary compliance burden by requiring the PC/TP to document an administrative process instead of simply demonstrating that data exchange occurs as needed for reliability. Furthermore, a requirement to have a “process” can become a point of contention and debate during an audit that unnecessarily distracts all parties from the real reliability need, which is the data exchange.

Part 1.5

It is similarly not clear that a “process” is really needed for Part 1.5. The drafting team should consider moving this topic to a separate requirement (such as a new Part 5.1) for the TP to provide the model data to the PC when deemed acceptable or consider if there is a real reliability need for this requirement at all. With the proposed changes to Requirement R2 below, the verified and validated model (and any necessary updates) should be available to the PC through MOD-032 processes, and if a PC requires additional data from the TP, the two entities should be able to reach agreement on an as-needed basis without needing a universal NERC requirement. Discussion during drafting team meetings indicates the drafting team appears to believe that Part 1.5 provides more flexibility for the PC/TP. However, Part 1.5 creates an unnecessary compliance burden by requiring the PC/TP to document an administrative process instead of simply demonstrating that data exchange occurs as needed for reliability. Furthermore, a requirement to have a “process” can become a point of contention and debate during an audit that unnecessarily distracts all parties from the real reliability need, which is the data exchange.

Part 1.6

Likewise, it is not clear that a “process” is really needed for Part 1.6, and the drafting team should move this topic to a separate requirement for the TP to provide its model data upon request. Discussion during drafting team meetings indicates the drafting team appears to believe that Part 1.6 provides more flexibility for the PC/TP. However, Part 1.6 creates an unnecessary compliance burden by requiring the PC/TP to document an administrative process instead of simply demonstrating that data exchange occurs as needed for reliability. Furthermore, a requirement to have a “process” can become a point of contention and debate during an audit that unnecessarily distracts all parties from the real reliability need, which is the data exchange.

To address these concerns, ERCOT recommends that Requirement R1 be revised and new Requirement R7 be added, as follows:

R1. Each Transmission Planner and its Planning Coordinator shall jointly develop requirements and processes for submission of documentation of Model Verification and Model Validation that 1) are made available to Generator Owners and Transmission Owners by the Transmission Planner and 2) include at a minimum the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning and Long-term Planning]

1.1. Specification of the limiting and protective functions listed within Table 1.1 of Attachment 1 that are required to be represented in the model;

1.2. For the facilities listed in Applicability Sections 4.2.5 and 4.2.6 (Inverter-Based Resources), Section 4.2.3.2 (FACTS devices), Section 4.2.4.1 (LCC HVDC), and Section 4.2.4.2 (VSC HVDC):

1.2.1. Identify the legacy1 facilities for which electromagnetic transient (EMT) model(s) are required under Requirement R3; and

1.2.2. Specify acceptable format and level of detail for EMT models.

R7. Each Transmission Planner shall provide the current (in-use) model data for an existing facility within 90 calendar days of receiving a written request for such data from the Generator Owner(s) or Transmission Owner(s) that own the facility that is the subject of the request.

Comments on Requirement R2:

MOD-026-2 should make a clearer distinction between verification and validation. While it may be reasonable to have a validation periodicity that involves staging tests or relying on disturbance events, unverified models (*i.e.*, models that do not properly reflect field or design settings, etc.) should never be submitted. Facility owners should continuously maintain Model Verification documentation, which should be available for submission on much shorter timelines than Model Validation documentation, especially after a facility settings modification. Separate requirement specifications for verification and validation would be the most straightforward way to facilitate this outcome.

Furthermore, the use of the term "verified model" in Requirement R2 is confusing given that it is not aligned with the proposed defined term for Model Verification. Fundamentally, the intent should be to require Model Verification and Model Validation of models already submitted through MOD-032, and it is redundant to require submission of a model under MOD-026, too (such a duplicative process potentially has no reliability benefit if models verified and validated through MOD-026 are not submitted through MOD-032 processes). The following proposed language eliminates the need to use the term "verified model:"

R2. Each Generator Owner or Transmission Owner shall provide to its Transmission Planner, within the timeframe(s) specified in Attachment 2, documentation of Model Verification and Model Validation for positive sequence dynamic model(s) submitted in accordance with MOD-032* that:

2.1. Verifies that the model represents the in-service equipment of the facility according to the requirements and process developed in Requirement R1;

2.2. Verifies that the configurable, site-specific parameters of the model(s) represent parameters of the in-service equipment of the facility, for those parameters that can be confirmed by the Generator Owner or Transmission Owner;

2.3. Verifies that the model includes the information and functions described in Attachment 1; and

2.4. Confirms through Model Validation that the simulated model response aligns with the actual recorded response of the modeled facility or demonstrates that the response of the facility positive sequence dynamic model(s) aligns with the response of the facility EMT model(s) provided under Requirement R3 for large signal disturbances. The confirmation or demonstration shall include the evaluation of:

2.4.1. The response to a dynamic reactive power or voltage excursion event using either a staged test or a measured system disturbance; and

2.4.2. The response to a dynamic active power or frequency excursion event using a staged test or a measured system disturbance.

*Model Verification or Model Validation activities that identify a need to change model parameters shall trigger submission of updated models according to MOD-032 processes.

Comments on Requirement R3:

Requirements for provision of an EMT model in MOD-026 will require careful coordination with Project 2022-04 to avoid conflicts and inefficiencies that could arise if multiple standards require provision of EMT models.

In multiple instances Requirement R3 requires only comparisons of model response to facility response. Facility owners (including IBR owners) should be obligated to submit accurate models that match actual facility response, not just comparisons. The burden of identifying model inaccuracies should not fall solely on the TP through Requirement R5. FERC Order No. 901 explicitly directs that facility owners (including IBR owners) should be required to submit accurate models. For example, paragraph 141 of Order No. 901 includes the following directive (emphasis added):

“We also direct NERC to require the **generator owners of registered IBRs** and the transmission owners that have unregistered IBRs on their system to **provide** to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) **dynamic models that accurately represent** the dynamic performance of registered and unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior.”

Additionally, the use of the term “verified” within Requirement R3 is confusing and unnecessary. If a model submission satisfies Parts 3.1 through 3.5, the model would necessarily be “verified,” so there is no need to use that term in the body of Requirement R3. It would also be beneficial for the EMT model to include information from Attachment 1, similar to the positive sequence model.

Additionally, the reference to “Attachment 2, Note 1” in Part 3.5 could cause confusion, as this note is distinct from the footnotes in the standard, and this part of Attachment 2 doesn’t seem at all related to the topic of “periodicity” that Attachment 2 is designed to address. Further, it is not clear why this Note 1 refers to Unit Model Validation while Part 3.5 applies to the EMT facility model. Additionally, it is not clear why “excursion” criteria are specified for frequency events but not voltage events. Specifying excursion criteria does not seem necessary, but if there is a reliability benefit to specifying these criteria, the criteria should include both frequency and voltage and be specified in a separate Attachment 3 (which could have the following title: Voltage and Frequency Event Excursion Criteria). To address these concerns, ERCOT proposes that Requirement R3 be revised to read as follows:

R3. For facilities identified under Applicability Sections 4.2.3.2, 4.2.4, 4.2.5, and 4.2.6, each Generator Owner or Transmission Owner shall, within the timeframe(s) specified in Attachment 2, provide a facility EMT model(s) and accompanying information that represent the in-service equipment of the facility to its Transmission Planner according to the requirements and processes developed by its Transmission Planner and Planning Coordinator in Requirement R1, Part 1.2. The facility EMT model(s) and accompanying information shall include at a minimum the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

3.1. Test6 result(s) demonstrating that the facility’s response aligns with the facility’s EMT model response for large signal disturbances. For an IBR, test result(s) are only necessary for the IBR unit.7 If test results are not obtainable, the Generator Owner or Transmission Owner shall document the reason;

3.2. Documentation of Model Verification demonstrating that the configurable, site-specific parameters of the submitted facility model(s) represent parameters of the in-service equipment of the facility, for those parameters that can be confirmed by the Generator Owner or Transmission Owner, and verification that the model includes the information and functions described in Attachment 1;

3.3. A facility EMT model with associated parameters representing the applicable HVDC, FACTS devices, IBR unit(s), collector system, auxiliary control devices8, power plant controller, generator step-up transformer, and main transformer(s) shall include:

3.3.1. Enabled protections that directly trip the IBR unit(s) or facility;9 and

3.3.2. Limiting functions that limit active/reactive output of the IBR unit(s) or facility.10

3.4. Documentation of Model Validation of the facility EMT model response using the recorded response of a dynamic reactive power or voltage excursion event from either a staged test or a measured system disturbance demonstrating that the simulated response aligns with the actual recorded response; and

3.5. Documentation of Model Validation of the facility EMT model response using the recorded response of a dynamic active power or frequency excursion event from either a staged test or a measured system disturbance demonstrating that the simulated response aligns with the actual recorded response.

If Model Validation for the facility model is required by Parts 3.4 and 3.5, the purpose and reliability need for required testing in Part 3.1 is unclear. For non-IBR facilities, Part 3.1 testing would be redundant, and if an IBR facility model is validated through Parts 3.4 and 3.5 it is not clear what benefit is provided by an IBR unit model validation for an in-service facility. Such IBR unit test results may provide evidence of the accuracy of models used for interconnection studies (prior to construction), but do not seem necessary for in-service facilities subject to MOD-026. If the drafting team desires to keep Part 3.1, the team should consider whether an outside entity (such as the TP) should determine whether the reason test results are not obtainable is acceptable. Otherwise, Part 3.1 seems to essentially be optional, as the facility owner could cite any reason, such as cost, to explain why test results are not obtainable. Additionally, ERCOT proposes that Part 3.6 be moved to Requirement R2 because it addresses the positive sequence model (*i.e.*, the intent of Part 3.6 appears to be to require the positive sequence model response to align with the verified and validated EMT model).

Comments on Requirement R4:

The language in Requirement R4 does not seem to align with published NERC recommendations, such as page 30 in: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20(1).pdf, which indicates that changes that alter electrical output should be studied PRIOR to implementation. In other words, a model reflecting a change should be available before the change is implemented. It should not take 365 or even 180 days after implementation to perform Model Verification, though it might take longer to perform Model Validation, which involves staging tests or relying on disturbance events (this is an instance in which using the term "verified" to mean both "verified" and "validated" may cause confusion and inefficiency). To address this concern and better align MOD-026-2 with published NERC recommendations, ERCOT proposes that Requirement R4 be revised to read as follows:

R4. Each Generator Owner or Transmission Owner, upon making a hardware, software, firmware, control mode, or setting change to any applicable in-service equipment that alters the equipment's dynamic response characteristic(s),11 shall provide its Transmission Planner the following, within the timeframe described in Attachment 2: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. Documentation of Model Verification in accordance with Requirement R2 and Requirement R3 reflecting the change(s) made; and

4.2. Documentation of Model Validation in accordance with Requirement R2 and Requirement R3 reflecting the change(s) made.

Comments on Requirement R5:

The TP's response time is not directly related to model verification or validation periodicity. Consequently, specifying the TP's response time within the requirement would be much clearer than referencing Attachment 2. Furthermore, MOD-026-1 requires 90-day response times, and it is not clear why MOD-026-2 proposes to extend that to 120 days. Additionally, due to the impracticalities (noted above as part of ERCOT's comments on Requirement R1, Part

1.3) associated with specifying acceptance criteria, the TP should be allowed to use its engineering judgment to identify technical concerns that need to be addressed (similar to the current MOD-026-1 approach) instead of having to attempt to develop acceptance criteria. If the drafting team can identify any universal baseline criteria that should be applied, those criteria should be clearly specified within the standard. To address these concerns, ERCOT recommends that Requirement R5 be revised to read as follows (while specific universal criteria could be added to this Requirement, acceptance of model validation and verification is (as noted above) largely a matter of engineering judgment):

R5. Each Transmission Planner after receiving documentation of Model Verification and Model Validation from the applicable Generator Owner or Transmission Owner pursuant to Requirements R2, R3, or R4, shall review each submission and provide a written response to the submitter within 90 days. The written response shall include one of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

• Notification of acceptance; or

• Notification of denial: technical concerns were identified in the documentation of Model Validation or Model Verification or the accompanying information. The notification of denial shall include an explanation and supporting evidence.

Comments on Requirement R6:

The facility owner's response time is not really related to model verification or validation periodicity. Consequently, specifying the facility owner's response time within the requirement would be much clearer than referencing Attachment 2. Furthermore, MOD-026-1 requires 90-day response times, and it is not clear why MOD-026-2 proposes to extend that to 120 days (particularly when the response can be a "plan" rather than actual validation activities). To address these concerns and align Requirement R6 with proposed changes to other requirements, ERCOT recommends that Requirement R6 be revised to read as follows:

R6. Each Generator Owner or Transmission Owner, after receiving a notification of denial under Requirement R5 or a request from its applicable Transmission Planner for a model review due to identified model or accompanying information deficiencies, shall provide a written response to its applicable Transmission Planner within 90 days. The written response shall contain one of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

• Updated documentation of Model Verification and Model Validation and accompanying information in accordance with Requirement R2 and Requirement R3;

• A plan to provide updated documentation of Model Verification and Model Validation and accompanying information in accordance with Requirement R2 and Requirement R3; or

• A resubmission of the current documentation of Model Verification and Model Validation and accompanying information in accordance with Requirement R2 and Requirement R3, with additional technical justification and supporting evidence to address the notification of denial or request for model review from the Transmission Planner.

Comments on Attachment 1:

Attachment 1 would benefit from a more descriptive title. MOD-026-2 already has an Applicability section, so using that term again for Attachment 1 is confusing. ERCOT recommends that the title for Attachment 1 be: *Model Functions and Information Subject to Model Verification*.

Model Validation should be addressed in the subparts of Requirements R2 and R3 rather than Attachment 1. Consequently, item 3 in all of the columns of Table 1.1, which refers to "Model Validation," should be deleted, and item 2 in the Volt/VAR Control and Frequency/ Power Control columns of Table 1.2, which refers to "Model Validation," should also be deleted.

Comments on and proposed language for Attachment 2:

ERCOT likewise recommends that Attachment 2 be given a more descriptive title, such as "Model Verification and Model Validation Periodicity." ERCOT also recommends changing the "Modeling Condition" heading in the table to "Circumstance," because the column seems to be describing a more generalized circumstance, situation, or scenario rather than a modeling condition, strictly speaking. Additionally, ERCOT recommends the rows within Attachment 2 be modified as follows:

Row 1: remove references to "verified model" (see proposed language in table below).

Row 2: remove references to "verified model" and establish different timelines for Model Verification and Model Validation (see proposed language in table below).

Row 3: remove references to "verified model" (see proposed language in table below).

Row 4: since the validation requirements allow a "staged" event, it is not clear why there is a need to address a scenario in which a specified level of frequency excursion is not experienced. ERCOT recommends deleting row 4 or potentially allowing validation using a less severe excursion (see also, ERCOT's related comments on Attachment 2, Note 1 in the comments on Requirement R3, above).

Row 5: appears to be missing.

Row 6: remove references to "verified model" and establish different timelines for Model Verification and Model Validation (see proposed language in table below).

Row 7: revise to be applicable only to Requirement R6, consistent with ERCOT's comments on and proposed revisions to Requirement R4 (above), and remove references to "verified model" (see proposed language in table below).

Row 8: delete entire row, consistent with ERCOT's proposed edits to Requirement R5.

Row 9: delete entire row, consistent with ERCOT's proposed edits to Requirement R6.

Row 10: remove references to "verified model" (see proposed language in table below).

Row 11: delete entire row, as it appears to be unnecessary. If a facility is not responsive by design, that facility's model performance should still be verified and validated through the normal processes. A better approach to address the underlying concern would be to include a footnote in Attachment 1 indicating that certain facilities may have been approved for operation without volt/VAR control capability and those facilities are required to provide documentation of that approval in lieu of Model Verification of explicit volt/VAR control functions listed in Attachment 1. Model Validation for a voltage excursion event should still be required in this case to validate that the model does indeed accurately reflect actual measured performance. Otherwise, row 11 implies that any facility owner could unilaterally exempt itself from all Model Verification and Model Validation requirements related to volt/VAR control simply by disabling that function on its equipment.

Row 12: delete entire row, as it appears to be unnecessary. If a facility is not responsive by design, that facility's model performance should still be verified and validated through the normal processes. A better approach to address the underlying concern would be to include a footnote in Attachment 1 indicating that certain facilities may have been approved for operation without frequency/power control capability and those facilities are required to provide documentation of that approval in lieu of Model Verification of explicit frequency/power control functions listed in Attachment 1. Model Validation for a frequency excursion event should still be required in this case to validate that the model does indeed accurately reflect actual measured performance. Otherwise, row 12 implies that any facility owner could unilaterally exempt itself from all Model Verification and Model Validation requirements related to frequency/power control simply by disabling that function on its equipment.

Row 13: explicitly specify the required action rather than referring back to row 3. Furthermore, ERCOT proposes that satisfying the net capacity factor criteria should only exempt the facility owner from more burdensome Model Validation, while Model Verification should still be required on the normal schedule for low-capacity-factor facilities to provide some degree of model fidelity check (see proposed language in table below).

Row 14: if the PC/TP have the discretion (and the obligation under Requirement R1, Part 1.2) to determine which legacy facilities are applicable for Requirement R3, any exemptions should be at the complete discretion of the PC/TP, who should not be required to accept exemptions that could lead to inaccurate simulation results and could potentially result in operating events if these exemptions are requested in certain critical areas. Consequently, ERCOT recommends that row 14 be deleted. If the drafting team still deems it necessary to address this topic, a better approach would be to revise footnote 1 to explicitly allow the PC/TP to consider availability of OEM support when identifying facilities pursuant to Requirement R1, Part 1.2.1.

NOTE 1: delete or possibly replace with an Attachment 3, consistent with ERCOT's comments above related to Requirement R3.

To address its concerns, ERCOT proposes the following revised language for Attachment 2 (row numbers align with posted draft but should be updated to account for the missing row 5 and other deleted rows):

MOD-026-2 Attachment 2

Model Verification and Model Validation Periodicity

Row 1 -- Circumstance

Establishing the initial Model Verification and Model Validation date for an applicable facility.

(Applies to Requirement R2 and Requirement R3)

Row 1 -- Required Action

For Requirement R2, transmit the documentation of Model Verification and Model Validation and accompanying information to its Transmission Planner in accordance with the date(s) of the Implementation Plan.

For Requirement R3, transmit the documentation of Model Verification and Model Validation and accompanying information, including the facility EMT model, to its Transmission Planner in accordance with the date of the Implementation Plan or within 365 calendar days after the Transmission Planner identifies the facility as an applicable facility in accordance with Requirement R1, Part 1.2, whichever is later.

Row 2 -- Circumstance

Initial Model Verification and Model Validation for a newly commissioned facility.

(Applies to Requirement R2 and Requirement R3)

Row 2 -- Required Action

Transmit documentation of Model Verification and accompanying information (Parts 2.1, 2.2, 2.3, 3.2, and 3.3) to its Transmission Planner within 30 calendar days after the commissioning date.

Transmit documentation of Model Validation and accompanying information (Parts 2.4, 3.4, and 3.5) to its Transmission Planner within 365 calendar days after the commissioning date.

Row 3 -- Circumstance

Subsequent Model Verification and Model Validation for an applicable facility.

(Applies to Requirement R2 and Requirement R3)

Row 3 -- Required Action

Transmit documentation of Model Verification and Model Validation and accompanying information (Parts 2.1, 2.2, 2.3, 2.4, 3.2, 3.3, 3.4, and 3.5) to its Transmission Planner within 10 calendar years of the most recent transmittal.

For the transmittal to reset the 10-year anniversary transmittal date for Requirement R2 and Requirement R3, all model(s) and model parameters must be verified and validated according to the applicable requirement(s) and included in the transmittal.

Row 6 -- Circumstance

An existing applicable facility with a change to in-service equipment as described under Requirement R4.

(Applies to Requirement R4)

Row 6 -- Required Action

Transmit documentation of Model Verification and accompanying information (Parts 2.1, 2.2, 2.3, 3.2, and 3.3) to its Transmission Planner within 30 calendar days after the facility is returned to service subsequent to making a change to in-service equipment.

Transmit documentation of Model Validation and accompanying information (Parts 2.4, 3.4, and 3.5) to its Transmission Planner within 365 calendar days after the facility is returned to service subsequent to making a change to in-service equipment.

For the transmittal to reset the 10-year anniversary transmittal date for Requirement R2 and Requirement R3, all model(s) and model parameters must be verified and validated according to the applicable requirement(s) and included in the transmittal.

Row 7 -- Circumstance

The Generator Owner or Transmission Owner has provided a plan to update documentation of Model Verification and Model Validation.

(Applies to Requirement R6)

Row 7 -- Required Action

Transmit updated documentation of Model Verification and Model Validation and accompanying information (Parts 2.1, 2.2, 2.3, 2.4, 3.2, 3.3, 3.4, and 3.5) to its Transmission Planner within 365 calendar days after the submittal of the update plan pursuant to Requirement R6.

Row 10 -- Circumstance

Existing, new, or upgraded generating unit or synchronous condenser that is equivalent to other unit(s) at the same physical location.

AND

Each unit has the same MVA nameplate rating.

AND

The nameplate rating is ≤ 350 MVA.

AND

Each unit has the same components and settings.

AND

The model for one of these equivalent units has been verified.

(Applies only to Requirement R2 for facilities identified in Table 1.1 of Attachment 1)

Row 10 -- Required Action

Document circumstance with a written statement and include with the documentation of Model Verification and Model Validation and accompanying information provided to its Transmission Planner for the equivalent unit.

Perform Model Verification and Model Validation for a different equivalent unit during each 10-year verification period.

Row 13 -- Circumstance

Existing applicable facility has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31, of 5% or less.

(This periodicity exemption applies only for Model Validation requirements under Requirements R2 and R3. Satisfying the net capacity factor criteria does not exempt a facility owner from Model Verification obligations under Requirement R3; it also does not exempt a facility owner from obligations under Requirements R4 or R6.)

Row 13 -- Required Action

Transmit documentation of Model Verification and accompanying information (Parts 2.1, 2.2, 2.3, 3.2, and 3.3) to its Transmission Planner within 10 calendar years of the most recent transmittal.

In lieu of documentation of Model Validation (Parts 2.4, 3.4, and 3.5), annually transmit a written statement to its Transmission Planner explaining that the facility is exempt because it satisfies the net capacity factor criteria.

If the current average net capacity factor over the most recent three calendar years exceeds 5%, then transmit documentation of Model Verification and Model Validation and accompanying information (Parts 2.1, 2.2, 2.3, 2.4, 3.2, 3.3, 3.4, and 3.5) to its Transmission Planner within 365 calendar days.

For the definition of net capacity14 factor refer to Appendix F of the GADS Data Reporting Instructions.15

Comments on the Technical Rationale:

There appear to be some extraneous words and a repeated sentence in the Large Signal Disturbances paragraph at the bottom of page 8. ERCOT recommends that the extraneous and repeated text be deleted, as follows:

Large Signal Disturbances - In the context of MOD-026-2, a large signal disturbance is typically the result of a fault on the transmission system, a loss of generation, a loss of a large load, or a switching of a heavily loaded transmission line.

The Attachment 2, Row 13 paragraph on page 12 indicates that the net capacity factor exemption was not intended to be available to IBRs, but the text of row 13 does not make that apparent intent clear, especially since the posted draft of row 13 does reference Requirement R3, which seems to be an inconsistency.

ERCOT believes it would be beneficial to provide the Rationale for each row included in Attachment 2.

It would also be helpful if the Technical Rationale included hyperlinks to the supporting documents that are referenced.

Likes 0	
Dislikes 0	

Response

The DT does not view the relationship between MOD-026-2 and MOD-032 in the way implied throughout the ERCOT comments. Rather, the DT envisions that it is the models submitted and accepted under MOD-026-2 that are then submitted for MOD-032. A few particulars should be noted.

First, MOD-026-2 requires documentation of Model Verification and Model Validation and requires TP/PCs to determine if the submitted model and documentation are acceptable. If models were submitted under MOD-032 and documentation under MOD-026-2, a rejection of the Model Verification and Model Validation documentation would also require a rejection of the model submitted under MOD-032. This would be a confusing process.

Second, MOD-032 submissions are required at a strict, essentially annual basis. The models and documentation required under MOD-026-2 have more nuanced timelines and can be triggered by other events (e.g., changing equipment settings or a model review initiated by a TP). If only models submitted under MOD-032 were reviewed, MOD-026-2 would have to require a new MOD-032 submission for these conditions. This is not consistent with MOD-032 timing requirements.

Third, MOD-026-2 has a separate resolution process with associated timing requirements. These, again, are not consistent with MOD-032. Should a model submitted under MOD-032 be rejected under MOD-026, the competing resolution processes would cause confusion.

The DT appreciates ERCOT's comments and desire for consistency between the standards. However, for the reasons explained above, the DT would suggest that if the relationship between the standards is made more explicit, it is MOD-032 that should require models accepted under MOD-026-2 when the facilities submitting models have become commercial and are now subject to MOD-026-2. The DT assigned to NERC project 2022-02 has taken steps to create this link in the most recent draft of MOD-032-2 which requires models approved under MOD-026 if such models are available.

Regarding Applicability, the DT appreciates the detailed comments and has made several changes in response. Applicability sections 4.2.1 and 4.2.2 are now specifically limited to synchronous generating units and facilities. Applicability section 4.2.5 continues to capture IBRs that meet the BES definition. For section 4.2.3, the DT utilized a threshold similar to the BES threshold for generating units (see Inclusion I2) to exclude less impactful devices from mandatory verification and validation activities. While the DT acknowledges this creates a category of equipment without mandatory verification and validation, including all such facilities would be inconsistent with the approach taken with generating units. Moreover, the standard does not preclude or limit an entity from developing requirements that exceed the standard.

Regarding Applicability 4.2.7, the DT has removed this section.

Regarding Part 1.1, please see the response above regarding MOD-032. The intent is that models accepted under MOD-026-2 would also be accepted under MOD-032. Part 1.1.1 is retained, but is clarified. The DT's intent was that Transmission Planners and Planning Coordinators would specify which limiting and protective functions they require to be represented in submitted models.

Regarding Part 1.3, the DT has made significant modifications to the language of this Part to clarify the intent. In general, the aim of Requirement R1 is for Transmission Planners and Planning Coordinators to develop a requirements for submitted models and accompanying documentation, and make those available to GOs and TOs. This transparency allows GOs and TOs the opportunity to assess their own models and identify potential shortcomings before submitting. Part 1.3 has been reworded to state that any requirements the TP and PC have developed in addition to the mandatory model requirements of Parts 1.1 and 1.2 must be made available to GOs and TOs.

Regarding Parts 1.4, 1.5, and 1.6, the DT has taken ERCOT's suggestion and removed the administrative, process-oriented requirements. Part 1.6 has been moved into a new Requirement R7 that is focused on the necessary action, rather than the establishment of a process.

Regarding Requirement R2, please see the response above regarding MOD-032. The standard does require that submitted models include documentation of Model Verification, including in instances where the plant had a settings modification. Decoupling Model Verification from Model Validation would require a significant overhaul of the standard. Prior to MOD-026, facility models should be submitted for reliability studies. The DT suggests that ERCOT consider if their processes developed for compliance with standards such as FAC-001 are the appropriate place to require models that include documentation of Model Verification against the facility design. The DT has replaced usage of the term "verified model" throughout the standard with language that points to the relevant requirement Parts.

Regarding Requirement R3, the DT agrees that facility owners (including IBR owners) should be submit accurate models. However, as ERCOT noted in their comments regarding Part 1.3, model accuracy is "a matter of engineering judgment." The DT agrees and is thus unable to prescribe quantitative criteria to determine if a model is "accurate". Thus, MOD-026-2 requires GO/TOs to submit the models and accompanying documentation of Model Verification and Model Verification, and requires the TP to determine if such models are acceptable. The official determination does fall on the TP (though the GO/TO may challenge it), but the provisions of Requirement R1 exist to provide

GO/TOs with clear expectations of the TP/PCs requirements. This gives GO/TOs clarity on expectations, and allows them to submit comparisons that meet those expectations in their judgment. Ultimately, the DT recognizes that assessments that involve engineering judgment are likely to have push and pull between the involved parties.

The DT has taken the suggestion to remove the term “verified model” and make explicit reference to Requirement Parts instead. This same approach has been taken with Requirement R2 for consistency.

The excursion criteria for frequency events are existing in MOD-027-1. MOD-026-1 does not have any similar requirements for voltage excursions. The DT has not elected to modify this aspect of the original standards, though the thresholds for frequency deviations have been updated to the latest values. It should be noted that the frequency deviation criteria serve a function that voltage deviations do not. For facilities that are unable to perform staged testing for active power or frequency response validation, the facility or unit is exempt from submitting validation if no frequency excursion meeting the associated criteria occurs.

Regarding Requirement R4, the DT agrees that proposed modifications that affect the electrical output should be studied prior to implementation. However, MOD-026-2 is not a study standard. Such modifications should be captured by TP/PCs under FAC-002 and studied for approval. Subsequent to the changes being made, MOD-026-2 requires updated models and documentation. For example, if a GO proposed to change its voltage control deadband, the change would be studied under TP/PC procedures defined under FAC-002 (see Requirement R1). Assuming the proposed change is approved, and the GO implements the proposed change in the field, the GO must then perform Model Verification and Model Validation and submit the updated models and documentation under MOD-026-2.

Regarding Requirement R5, the DT has included the timelines in the Requirement language as suggested. The DT has also reverted the timing requirement to 90 days as in MOD-026-1. The DT does not intend to preclude TPs from using engineering judgment in their reviews. However, areas where engineering judgment is used should still be specified in the TP/PCs requirements made available to GO/TOs. For example, a TP/PC may elect to provide examples of model response benchmarking that were deemed acceptable and unacceptable. This provides GO/TOs with a clearer understanding of the expectations, even if numeric criteria are not provided. The DT has attempted to balance the flexibility required by TP/PCs with the clarity needed by GO/TOs.

Regarding Requirements R6, the DT has included the timelines in the Requirement language as suggested. The DT has also reverted to 90 days as in MOD-026-1. It should be noted that responses to ad-hoc model reviews utilize a longer timeline of 180 days.

Regarding Attachment 1, the attachment title was an unintentional error. The title has been removed, and the attachment is consistently referred to as “Attachment 1”. The DT has moved Model Validation requirements into Requirement R2 to align with Requirement R3, as suggested.

Regarding Attachment 2, the title of this attachment was also an error and has been similarly addressed. The DT has made numerous edits to Attachment 2, adopting several of ERCOT’s recommendations. The exemption of row 4 was carried over from MOD-027-1. The DT has clarified that this exemption only applies for units where a staged test is not possible. Rows 11 and 12 have been updated to requirement a written statement explaining the facility’s equipment does not respond to voltage or frequency events, respectively. The exemption of row 14 has been integrated into Requirement R3. While mandatory models for all legacy facilities would benefit Transmission Planners, the DT must consider the practical obstacles to achieving this. For GOs and TOs with legacy equipment no longer supported, the DT does not think the inability to obtain a model should result in a compliance violation for the facility owner. Rather, the DT would suggest that TPs cooperate with GOs and TOs with such facilities to determine what options may be available, or if a similar model may be available that could reasonably replicate the equipment behavior. These efforts may serve to improve system reliability, but should not be mandated.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
Please address the lack of consistent capitalization of “Model Verification” and “Model Validation” throughout the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, this has been addressed in clarifying edits.	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	
Document Name	
Comment	

WAPA recommends for MOD-026 R3.6, "Large Signal Disturbance", be defined as, " A power grid event at 60 kV and greater captured by Category 1 or Category 2 generator Disturbance Monitoring Equipment (such as PRC-028 equipment)". This helps bound and define what is reasonable while still achieving the desired NERC objective. It is not reasonable to leave large signal disturbance as open ended where an auditor could decide an entity to induce a large signal disturbance. Inducing a large signal disturbance could actually cause a grid event, damage equipment or at a minimum cause unnecessary equipment loss of life. An example is a large switching event and / or cause mechanical torques on power transformers thus reducing their life and possibly causing serious damage. Also, Attachment 1 Excitation Control references outer-loop controls which are not currently included in some models. Can that either be removed or clarified as to when they are required.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment, the DT has changed the wording and added simulated in front of large signal disturbance response. The DT has also added after "as defined by the Transmission Planner." The DT did not want to define what a large signal disturbance is as it may vary region to region. The DT felt that the Transmission Planner should define what they look for as a large signal disturbance. The DT felt this was necessary to include, this will be clarified upon more in the technical rationale document.	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	
Document Name	
Comment	
MEC supports the comments of the MRO NERC Standards Review Forum and the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the response to MRO NSRF's comment.	
Rhonda Jones - Invenergy LLC - 5,6	

Answer	
Document Name	
Comment	

Invenergy would like to thank the drafting team for their hard work and for the opportunity to provide comments.

Requirement R1

The SDT should consider a uniform framework or minimum set of requirements that defines reliability-based expectations for Transmission Planners regarding the identification of legacy facilities for which EMT models are required. As drafted, the standard does not provide a foundation for a consistent approach.

Requirement R3

Should R3 also include facilities identified per Requirement R1 Part 1.2.1.? For example, a revised R3 could read:

“For facilities identified under the Applicability sections 4.2.3.2, 4.2.4, 4.2.5, and 4.2.6 or legacy facilities identified under Requirement R1 Part 1.2.1., each Generator Owner or Transmission Owner shall provide a verified EMT model(s) with associated parameters and accompanying information that represent the in-service equipment of the facility to its Transmission Planner according to the requirements and processes developed by its Transmission Planner and Planning Coordinator in Requirement R1 Part 1.2, within the timeframe specified in Attachment 2.”

Auxiliary control devices, even limited by footnote 8 to only those auxiliary control devices that act on voltage and/or frequency, is too vague a category and may include devices that OEMs do not model. Please consider replacing the use of “auxiliary control devices” with “static and dynamic reactive support equipment.”

Please consider revising Part 3.3.1. to read, “Enabled protection settings per PRC-024-4 or PRC-029-1 that directly trip the IBR unit(s) or facility; and”. If this change were made, footnote 9 could be removed. There are numerous protection functions that may rely, either fully or partially, on voltage and/or frequency, yet are not represented in electrical simulation models, whether dynamic or EMT. Additionally, other protection functions may operate based on parameters unrelated to voltage or frequency. As noted in footnote 9, it is not feasible to capture an exhaustive set of protection functions for a given piece of equipment. Mandating the inclusion of all protection functions that could act on voltage and/or frequency, beyond those covered by PRC-024-4 or PRC-029-1, would not compel GOs and TOs to require OEMs to disclose them, due to intellectual property constraints. While some functions may be included, the entirely black-boxed nature of these models makes verification impossible.

Likes 0	
Dislikes 0	
Response	

The concern here is that without any guidelines for the TPs on what legacy facilities they could require EMT models for, TPs could require EMT models for all legacy facilities - which will be very burdensome for GO/OEMs. I think, though, that it'll be difficult to provide such guidance in the standard, not sure if other team members have thoughts on this.

The term "Auxiliary control device" is unclear and could be misinterpreted as referring to auxiliary equipment within the inverter or WTG, such as motors, HVAC systems, etc.

I believe the intent here is to include other devices within the IBR plant, such as capacitor banks, SVCs, and similar equipment. If that's the case, a more explicit term like "reactive power support equipment" would better convey the intended meaning.

An IBR plant includes numerous protection elements beyond the IBR unit's own protection. These external protections are coordinated with the IBR unit's capabilities and are designed to trip only when the plant operates outside those capabilities - based on PRC-19. Modeling all of these protection elements in an EMT model would unnecessarily complicate the simulation without providing meaningful gains in accuracy.
I recommend that we modify 3.1.1 to only require modeling of all protections that could directly trip the IBR units, but exclude other IBR plant protections, such as collector feeders' protection, transformers protection, and other substation-level elements.

Also, I recommend removing the "feeder" protection from footnote 7. All of the feeder protections should be coordinated with the plant capabilities, based on PRC-19. Also, I am not sure if there is no known acceptable methodology to model an "equivalent" protection that would represent all the protection elements of the disaggregated collector feeders.

Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	
Document Name	MOD-026-2 R3 Suggestions (ITC).docx
Comment	

Comments:

1. Change the Applicability Section as follows:

Generator Owners owning:

4.2.1 GO – Category 1 Synchronous.

DELETE Also includes GOs in 4.2.5 and is covered by 4.2.1

4.2.2. GO-Category 1 Inverter-Based Resources (IBR);

4.2.3. GO Category 2 IBR

Transmission Owners owning:

4.2.4. Dynamic reactive resources with a gross (individual or aggregate) nameplate rating greater than 20 MVA including, but not limited to:

4.2.3.1. Synchronous condenser; and

4.2.3.2. Flexible alternating current transmission system (FACTS) devices.

4.2.5. High-voltage direct current (HVDC) systems;

4.2.7 – DELETE Conflicts with 4.2.6

A GO or TO looking for a waiver for any Legacy facilities for which electromagnetic transient (EMT) model(s) would be required under Requirement R3 shall request it from their TP. A legacy facility for the purpose of this standard is any facility with an in-service date prior to the effective date of MOD-026-2.

2. Move Periodicity Information to each applicable Requirement. (As currently provided it is hard to follow for initial compliance and new people trying to comply with the requirements. See R2 below for an example.

3. Modify the requirements and measures as identified below and in the attachment.

R1 Modify R1 to only the TP shall develop dynamic model verification requirements and processes.

4. Adjust per recommendations for Applicability

1.2.1 Move to Applicability

1.2.2 Change to Specify EMT model format and level of detail required. Unlike Positive sequence models, EMT will not have an acceptable model list.

Swap 1.3 and 1.4

M1 Measure is for both TP and PC while R1 only includes the TP.

Modify R2

R2 Each Generator Owner and Transmission Owner shall provide for their Applicable facilities: documentation of Model Verification of a positive sequence dynamic model(s) with associated parameters, any information pertaining to changes to the model(s) or its parameters, and the verified model(s) 4 to its Transmission Planner that:

Move Periodicity Information to each applicable Requirement. (As currently provided it is hard to follow for initial compliance and new people trying to comply with the requirements.

2.1 Each GO and To shall :

- Per the Implementation Plan or within 365 days for a Legacy unit not eligible for a waiver per the TP;
- Within 365 days of the commissioning date; or
- Within 10 calendar years of the most recent transmittal

2 Previous 2 Modify Each Generator Owner and Transmission Owner with applicable facilities shall provide: documentation of Model Verification of a positive sequence dynamic model(s) with associated parameters…(Add) according to the requirements and processes developed by its Transmission Planner and Planning Coordinator in Requirement R1 Part 1.1. The verified model(s) and accompanying information shall include at a minimum the following: Delete to its Transmission Planner that

2.3 Previous 2.2 but remove … by the GO or TO. This carries down from R2.

2.4 Previous 2.3

2.5 Is updated per R2.1.

Modify M2 see R2 example.

Modify R3

See attached revised R3.

R3.1 – Please provide clarity on what is exactly being requested.

(Please review and revise the Technical Rationale for this requirement along side of R2 as we believe there are contradictions.

R3.6 Should the work identifying the large signal disturbance response of the facility positive sequence dynamic model(s)be determines in R2.

M3 Modify see example R2

Modify R4 See R2 example. Move periodicity into the requirement.

M4 Modify see example R2

R5 Each Transmission Planner, after receiving the submitted model(s) and accompanying information from the applicable Generator Owner and Transmission Owner, shall …

- Preferably add a staged implementation for this work similar to that provided in MOD-026-1. If the DT does not believe a staged implementation is appropriate, please provide the option for the TP to identify and distribute a plan for the completion of the work similar to what is identified for the GO and TO.

- Move time frame into requirement and adjust to 150 days from 120.

R6 Modify see example R2

- Move time frame into requirement.

M6 Modify see example R2

4. The standard does not apply to the TOP so this entity should be removed from the Implementation Plan.

Likes 0	
Dislikes 0	

Response

The DT has added the word synchronous into the applicability section for 4.2.1 and for 4.2.2 based on comments received and has removed 4.2.7. After working with NERC Staff the DT has confirmed it has the correct entities cited, and how they are cited in the applicability section to cover all entities needed, and all entities needed to fulfill Order 901. The team has added the exemption language into Requirement R3 along with IP for legacy facilities in relation to EMT modeling. The timelines for Requirement R4, R5, and R6 have been moved up into the standard body language. Requirement R1 will not be modified to include only the TP as it essential to have both the TP and PC in coordination. The other reason is that for reliability purposes and in alignment with the ideas of FERC Order No. 901 both the TP and PC should have a Model Validated and Model Verified model.

Colin Chilcoat - Invenergy LLC - 5,6	
Answer	
Document Name	
Comment	

Invenergy would like to thank the drafting team for their hard work and for the opportunity to provide comments.

Requirement R1

The SDT should consider a uniform framework or minimum set of requirements that defines reliability-based expectations for Transmission Planners regarding the identification of legacy facilities for which EMT models are required. As drafted, the standard does not provide a foundation for a consistent approach.

Requirement R3

Should R3 also include facilities identified per Requirement R1 Part 1.2.1.? For example, a revised R3 could read:

"For facilities identified under the Applicability sections 4.2.3.2, 4.2.4, 4.2.5, and 4.2.6 or legacy facilities identified under Requirement R1 Part 1.2.1., each Generator Owner or Transmission Owner shall provide a verified EMT model(s) with associated parameters and accompanying information that represent the in-service equipment of the facility to its Transmission Planner according to the requirements and processes developed by its Transmission Planner and Planning Coordinator in Requirement R1 Part 1.2, within the timeframe specified in Attachment 2."

Auxiliary control devices, even limited by footnote 8 to only those auxiliary control devices that act on voltage and/or frequency, is too vague a category and may include devices that OEMs do not model. Please consider replacing the use of "auxiliary control devices" with "static and dynamic reactive support equipment."

Please consider revising Part 3.3.1. to read, "Enabled protection settings per PRC-024-4 or PRC-029-1 that directly trip the IBR unit(s) or facility; and". If this change were made, footnote 9 could be removed. There are numerous protection functions that may rely, either fully or partially, on voltage and/or frequency,

yet are not represented in electrical simulation models, whether dynamic or EMT. Additionally, other protection functions may operate based on parameters unrelated to voltage or frequency. As noted in footnote 9, it is not feasible to capture an exhaustive set of protection functions for a given piece of equipment. Mandating the inclusion of all protection functions that could act on voltage and/or frequency, beyond those covered by PRC-024-4 or PRC-029-1, would not compel GOs and TOs to require OEMs to disclose them, due to intellectual property constraints. While some functions may be included, the entirely black-boxed nature of these models makes verification impossible.	
Likes 0	
Dislikes 0	
Response	
The concern here is that without any guidelines for the TPs on what legacy facilities they could require EMT models for, TPs could require EMT models for all legacy facilities - which will be very burdensome for GO/OEMs. I think, though, that it'll be difficult to provide such guidance in the standard, not sure if other team members have thoughts on this. The term "Auxiliary control device" is unclear and could be misinterpreted as referring to auxiliary equipment within the inverter or WTG, such as motors, HVAC systems, etc. I believe the intent here is to include other devices within the IBR plant, such as capacitor banks, SVCs, and similar equipment. If that’s the case, a more explicit term like "reactive power support equipment" would better convey the intended meaning. An IBR plant includes numerous protection elements beyond the IBR unit’s own protection. These external protections are coordinated with the IBR unit’s capabilities and are designed to trip only when the plant operates outside those capabilities - based on PRC-19. Modeling all of these protection elements in an EMT model would unnecessarily complicate the simulation without providing meaningful gains in accuracy. I recommend that we modify 3.1.1 to only require modeling of all protections that could directly trip the IBR units, but exclude other IBR plant protections, such as collector feeders' protection, transformers protection, and other substation-level elements. Also, I recommend removing the "feeder" protection from footnote 7. All of the feeder protections should be coordinated with the plant capabilities, based on PRC-19. Also, I am not sure if there is no known acceptable methodology to model an "equivalent" protection that would represent all the protection elements of the disaggregated collector feeders.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	

Comment	
OPG supports the following NPCC Regional Standards Committee's comments: "R1-1.1.1. The goal of R1 is to "develop dynamic model verification requirements and processes". R1-1.1.1 indicates: "Specify the limiting and protective functions listed within Table 1.1 that are required to be represented in the model" This is not a verification requirement or process; it is a modelling requirement which is not the intended goal of MOD-026. R1-1.1.1. should be removed. R1-1.2.-1.2.1. and 1.2.2. This should not be part of the "Verification and Validation" document. This is a modelling requirement. FAC-002-5 currently being developed by NERC project 2022-04 covers this by requiring TP/PC to develop and publish their EMT modelling requirements (in R1-1.1.). R1-1.2. should be removed. R3-3.3. is a modeling requirement. It should be rephrased to verify this information is included to the model. MOD-026, as proposed, covers verification and validation of models. It should also cover model quality assessment (the process of evaluating the plausibility, usability and numeric stability of a model based on a review of model documentation, data, and simulations), by the TP/PC to ensure the modelling requirements are met and the model can be used for the intended studies. MOD-026 seems like the standard who should cover this Unofficial Comment Form | MOD-026-2 Project 2020-06 Verifications of Models and Data for Generators | May 2025 3 Note 1 for should be removed. We suggest referencing the methodologies established to evaluate the models to indicate when a frequency event can be used to validate the model. (May also varies with the technology being tested) In Row 14 of attachment 2, the modelling condition seems to apply only to R3 (EMT). However, the same reasoning can be applied to R2, with difficulties obtaining a phasor domain model. Will R2 be included in the exemption?"	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to NPCC's comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
In Requirement R1 language "model verification" is not capitalized but it is capitalized (and not capitalized) in Measure M1. Is Requirement R3 Part 3.1 applicable to both BES and non-BES Inverter-Based Resources? In Table 1.1 Footnote 12 should say "Model Verification of Generator Model….." as "Generator Model Verification" is not a defined term. Should "active power" and "reactive power" be capitalized? Table 1.2 Volt/Var Control column has an	

additional "1" in bullet 2 in the phrase "Table 1.2 Volt/Var **1**" Within Table 1.1 Additional Limiting and Protective functions uses "ride-through". Should that be capitalized? Row 14 basically eliminates any compliance for an entity prior to the effective date of the Standard. Grandfathering the problem is not a solution to the risk. Every GO may simply send in a letter and the current issues will remain. Additionally, allowing no models for non-existent OEMs or one that no longer supports the in-service equipment would allow a hole in reliability to widen. Does the DT have any hard facts regarding these situations to capture the risk? OEMs may support the equipment at a price and the GO may decline that support.	
Likes 0	
Dislikes 0	
Response	
For Requirement R1, that wording has been replaced so the undefined term is not being used there. Requirement R3, Part 3.1 Thank you for the footnote solution, the DT will incorporate that in the footnote, and the 1 has been removed from Table 1.2. The term ride through is not capitalized as PRC-029 is not effective at this moment, along with the defined term. This will be capitalized once those are effective soon. Row 14 has been moved up into Requirement R3 as it is an exemption and should belong in the requirement language rather then Attachment 2. Thank you for the comment and support.	
Bob Cardle - Pacific Gas and Electric Company - 1,3,5 - WECC	
Answer	
Document Name	
Comment	
Pacific Gas and Electric Corporation supports the additional EEI comments.	
Likes 0	
Dislikes 0	

Response	
Please see the DT's response to EEI's comment.	
Bret Galbraith - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	
Document Name	
Comment	
1. The SDT uses the term "large" in Section 3.6. The SDT provides some guidance on examples of what "large" may entail, but none of the examples are quantitative and this makes it difficult for entities to show compliance, i.e., the rule is vague. Such vagueness can lead to not only different regions enforcing this Requirement differently, but even auditors in the same regions auditing it differently. Seminole requests the SDT to add more quantitative standards around this Requirement. 2. For footnote 11, if a like for like equipment change (same make and model) occur, would that trigger footnote 11? For footnote 11, if entities switch out a piece of equipment for a newer version, but retain the same configurations, is that considered a "change" per footnote 11? 3. Seminole understands that these revisions pertain to a FERC directive, however, the SDT has made a large amount of revisions and the SDT has not provided sufficient time for teams to review all of the changes.	
Likes 0	
Dislikes 0	
Response	
1.The drafting team has added language to better clarify what a large signal disturbance is. The language added will have the TP specify which large signal disturbances to include in the simulated model benchmarking. The DT considered the defined term "Disturbance," however, it did not address the concern being raised. 2. Footnote 11 has been struct with edits since the initial ballot to the MOD-026-2. 3. Thank you for the feedback, the changes include combinations of MOD-026-1 and MOD-027-1 into one standard along with other changes to address reliability needs identified in FERC Order No. 901 while meeting the FERC Order deadline.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	

Comment	
MRO NSRF strongly recommends for MOD-026 R3.6, "Large Signal Disturbance" be defined as, "A power grid event at 60kV and greater captured by Category 1 or Category 2 generator Disturbance Monitoring Equipment (such as PRC-028 equipment)". This helps bound and define what is reasonable while still achieving the desired NERC objective. It is not reasonable to leave large signal disturbance as open ended where an auditor could decide an entity needed to induce a large signal disturbance. Inducing a large signal disturbance could actual cause a grid event, damage equipment or at a minimum cause unnecessary equipment loss of life. An example is a large switching event and / or a fault causes mechanical torques on power transformers thus reducing their life and possibly causing serious damage.	
Likes 0	
Dislikes 0	
Response	
Requirement R3, Part 3.6 pertains to benchmarking the positive sequence model against the EMT model response and is not related to actual system disturbances. Therefore, there is no risk to equipment from this "simulated" large disturbance. Updates to the Part 3.6 language was made to clarify.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	

We appreciate the effort put forth by the DT to develop a draft of MOD-026-2 that complies with the broad scope of FERC Order 901. We understand that this is a monumental undertaking and is rife with difficulties; however, we believe that a few additional modifications would serve to better codify the intent behind this proposed Reliability Standard. Therefore, ACES recommends the following modifications to MOD-026-2:
 	
• Combine Sections 4.2.1 and 4.2.2 and 4.2.5 into a single applicability statement similar to the following:
    ○ BES generating resource(s)
• Strike Section 4.2.7. If a Facility is non-BES, then this (or any other) Reliability Standard is not applicable; excluding the resources identified in Section 4.2.6. To explicitly state this is redundant and potentially creates confusion by failing to explicitly list a facility wherein MOD-026-2 is not applicable.
    ○ In short, it is ACES opinion that Section 4.2 should only include a list of facilities where MOD-026-2 is applicable.
• The wording of Requirement R1, Part 1.6 is unclear as to which entity is being held to the 90 calendar day timeline. It is assumed that, since Requirement R1 is applicable to the TP/PC, the 90 calendar day timeline in Part 1.6 is applicable to the TP. Consequently, ACES recommends the following modification to Requirement R1 Part 1.6:	

R1. 1.6 Process for Generator Owner(s) or Transmission Owner(s) to request current (in-use) model data from its Transmission Planner for an existing facility owned by the Generator Owner(s) or Transmission Owner(s). 1.6.1 The Transmission Planner shall provide the current (in-use) model data to the applicable Generator Owner or Transmission Owner within 90 calendar days of receiving a written request. • It is the opinion of ACES that, as written, Requirement R2, Part 2.2 leaves the GO and/or TO in the unenviable position of "trying to prove the negative" for any parameters they are unable to confirm. We recommend adding language to this Requirement Part to allow for the GO/TO to communicate this to the TP via a written statement. In our opinion, this slight adjustment will allow the GO/TO to document the fact that they considered each configurable, site-specific parameter of the model(s). Thus, we recommend the following modification: R2. 2.2 Verifies that the configurable, site-specific parameters of the model(s) represent parameters of the in-service equipment of the facility. 2.2.1 For any parameters that cannot be verified, the applicable Generator Owner or Transmission Owner shall provide a written statement to the Transmission Planner detailing any such parameters and the reason(s) they cannot be confirmed. • The full text of footnote 11 was not captured on page 7 in the "clean" version of MOD-026-2 that was posted to the project page. This footnote is continued at the bottom of page 8. We believe that this will create confusion within the industry. Thus, we recommend that the DT ensure the full text of footnote 11 is included on the same page as Requirement 4. • There appear to be two related typos within the table in Attachment 2. Firstly, there does not appear to be a Row Number 5 within the table. Secondly, the Modeling Condition in Row Number 4 references Attachment 2, Row 5. We recommend renumbering the rows to include Row Number 5 and updating the reference in Row 4 to refer to the correct Row Number(s). Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
The drafting team (DT) has made edits based on suggestions provided around the Facility section of the MOD-026-2 standard. This section now has removed section 4.2.7 to provide clarity. The DT will not be combining the entities based on how they are used within the standard, such as Attachment 1. The DT modified Requirement R1, Part 1.6 based on the suggestion provided and has removed it into a separate Requirement R7.	

The DT agreed with the suggestion provided around Requirement R2, Part 2.2 and has added the subpart in and made conforming changes based on edits suggested. Finally, Footnote 11 has been removed based on edits from other commentors, and Row 5 has been added along with the correcting the reference to Row 5 in Row 4 of Attachment 2.

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2, Group Name PJM, MISO, SPP, NYISO joint comments	
Answer	
Document Name	
Comment	

Comments on the Purpose statement:

If the "models" referenced in the Purpose statement are intended to be the models submitted in accordance with MOD-032, that link should be made more explicit within MOD-026-2.   We propose the following revised purpose statement to provide the necessary clarification:

To confirm that the dynamic models and associated parameters used to assess Bulk Electric System (BES) reliability **accurately** represent the in-service equipment of BPS facilities, including generating facilities, transmission-connected dynamic reactive resources, and high-voltage direct current (HVDC) systems.

Comments on the Facilities portion of the Applicability section:

Section 4.2.7

Section 4.2.7 excludes facilities meeting an Exclusion of the BES definition; however, Exclusion E1b of the BES definition could certainly exclude facilities that meet the criteria in section 4.2.6:

• E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: . . .

b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

For example, a 70 MVA wind farm connected to a 115kV station through a single radial line would satisfy the E1b exclusion but would also meet section 4.2.6. As MOD-026-2 is currently written, it is not clear if MOD-026-2 would apply to such facilities (because of section 4.2.6) or exclude such facilities (because of section 4.2.7). We recommend that section 4.2.7 be deleted to remove this ambiguity. If the drafting team elects to retain section 4.2.7, the Technical Rationale should be updated to address section 4.2.7 and the Applicability section of MOD-026-2 should be revised to clarify whether the standard applies to facilities that meet both section 4.2.6 and section 4.2.7.

Comments on Requirement R1:

Part 1.3

The use of “criteria” could easily be interpreted by an auditor to mean quantitative criteria related to model accuracy. The P2800.2 team has struggled with this exact issue of how to evaluate accuracy and has ultimately concluded that accuracy evaluation is a matter of engineering judgment. MOD-026-2 should unambiguously adopt a similar position rather than implying that the PC/TP will be able to develop objective “criteria” to determine disposition under Requirement R5. Any validation should be deemed acceptable based on the engineering judgment of both the facility owner (prior to submission) and the TP (during evaluation of the submission). The Technical Rationale seems to suggest that the Part 1.3 reference to acceptance criteria was intended primarily to address model usability, but that intent is not at all clear in the draft requirement language for Part 1.3.

Comments on Requirement R3:

Additionally, the reference to “Attachment 2, Note 1” in Part 3.5 could cause confusion, as this note is distinct from the footnotes in the standard, and this part of Attachment 2 doesn’t seem at all related to the topic of “periodicity” that Attachment 2 is designed to address. Further, it is not clear why this Note 1 refers to Unit Model Validation while Part 3.5 applies to the EMT facility model. Additionally, it is not clear why “excursion” criteria are specified for frequency events but not voltage events. Specifying excursion criteria does not seem necessary, but if there is a reliability benefit to specifying these criteria, the criteria should include both frequency and voltage and be specified in a separate Attachment 3 (which could have the following title: Voltage and Frequency Event Excursion Criteria).

If Model Validation for the facility model is required by Parts 3.4 and 3.5, the purpose and reliability need for required testing in Part 3.1 is unclear. For non-IBR facilities, Part 3.1 testing would be redundant, and if an IBR facility model is validated through Parts 3.4 and 3.5 it is not clear what benefit is provided by an IBR unit model validation for an in-service facility. Such IBR unit test results may provide evidence of the accuracy of models used for interconnection studies (prior to construction), but do not seem necessary for in-service facilities subject to MOD-026. If the drafting team desires to keep Part 3.1, the team should consider whether an outside entity (such as the TP) should determine whether the reason test results are not obtainable is acceptable. Otherwise, Part 3.1 seems to essentially be optional, as the facility owner could cite any reason, such as cost, to explain why test results are not obtainable.

Comments on Requirement R5:

The TP’s response time is not directly related to model verification or validation periodicity. Consequently, specifying the TP’s response time within the requirement would be much clearer than referencing Attachment 2. Furthermore, MOD-026-1 requires 90-day response times, and it is not clear why MOD-026-2 proposes to extend that to 120 days. Additionally, due to the impracticalities (noted above is part of these comments on Requirement R1, Part 1.3) associated with specifying acceptance criteria, the TP should be allowed to use its engineering judgment to identify technical concerns that need to be addressed (similar to the current MOD-026-1 approach) instead of having to attempt to develop acceptance criteria. If the drafting team can identify any universal baseline criteria that should be applied, those criteria should be clearly specified within the standard. To address these concerns, we recommend that Requirement R5 be revised to read as follows (while specific universal criteria could be added to this Requirement, acceptance of model validation and verification is (as noted above) largely a matter of engineering judgment):

R5. Each Transmission Planner after receiving documentation of Model Verification and Model Validation from the applicable Generator Owner or Transmission Owner pursuant to Requirements R2, R3, or R4, shall review each submission and provide a written response to the submitter within 90 days. The written response shall include one of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

• Notification of acceptance; or

•	Notification of denial: technical concerns were identified in the documentation of Model Validation or Model Verification or the accompanying information. The notification of denial shall include an explanation and supporting evidence.

Comments on Requirement R6:

The facility owner’s response time is not really related to model verification or validation periodicity. Consequently, specifying the facility owner’s response time within the requirement would be much clearer than referencing Attachment 2. Furthermore, MOD-026-1 requires 90-day response times, and it is not clear why MOD-026-2 proposes to extend that to 120 days (particularly when the response can be a “plan” rather than actual validation activities). To address these concerns and align Requirement R6 with proposed changes to other requirements, we recommend that Requirement R6 be revised to read as follows:

R6.	Each Generator Owner or Transmission Owner, after receiving a notification of denial under Requirement R5 or a request from its applicable Transmission Planner for a model review due to identified model or accompanying information deficiencies, shall provide a written response to its applicable Transmission Planner within 90 days. The written response shall contain one of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

Comments on Attachment 1:

Attachment 1 would benefit from a more descriptive title. MOD-026-2 already has an Applicability section, so using that term again for Attachment 1 is confusing. The we recommend that the title for Attachment 1 be: *Model Functions and Information Subject to Model Verification*.

Model Validation should be addressed in the subparts of Requirements R2 and R3 rather than Attachment 1. Consequently, item 3 in all of the columns of Table 1.1, which refers to “Model Validation,” should be deleted, and item 2 in the Volt/VAR Control and Frequency/ Power Control columns of Table 1.2, which refers to “Model Validation,” should also be deleted.

Comments on and proposed language for Attachment 2:

We likewise recommend that Attachment 2 be given a more descriptive title, such as “Model Verification and Model Validation Periodicity.” We also recommend changing the “Modeling Condition” heading in the table to “Circumstance,” because the column seems to be describing a more generalized circumstance, situation, or scenario rather than a modeling condition, strictly speaking.

Row 5: appears to be missing.

To address its concerns, we propose the following revised language for Attachment 2 (row numbers align with posted draft but should be updated to account for the missing row 5 and other deleted rows)

Comments on the Technical Rationale:

There appear to be some extraneous words and a repeated sentence in the Large Signal Disturbances paragraph at the bottom of page 8. We recommend that the extraneous and repeated text be deleted, as follows:

Large Signal Disturbances - In the context of MOD-026-2, a large signal disturbance is typically the result of a fault on the transmission system, a loss of generation, a loss of a large load, or a switching of a heavily loaded transmission line stem, and that connect at a single point on the collector system. A large signal disturbance is typically the result of a fault on the transmission system, the loss of generation, the loss of a large load, or the switching of a heavily loaded transmission line.

The Attachment 2, Row 13 paragraph on page 12 indicates that the net capacity factor exemption was not intended to be available to IBRs, but the text of row 13 does not make that apparent intent clear, especially since the posted draft of row 13 does reference Requirement R3, which seems to be an inconsistency.

We believe it would be beneficial to provide the Rationale for each row included in Attachment 2.

It would also be helpful if the Technical Rationale included hyperlinks to the supporting documents that are referenced.

NYISO Abstains from the responses on Question 5.

Likes 0	
Dislikes 0	

Response

Purpose statement: The models submitted under MOD-026-2 are not meant to be the models submitted in accordance with MOD-032. MOD-026 requires the submission of verified and validated generator models as where MOD-32 requires the submission of data and models for modeling the entirety of the network. While generator dynamic models are subset of the data required under MOD-032, MOD-032 makes no mention of verifying to validating these models.

The DT believes “represents” and “accurately represents” are synonymous, it has added the wording “synchronous in front of 4.2.1, and 4.2.2. The DT has agreed to remove the propose 4.2.7 section.

The intent of 1.3 is to allow the TP the discretion to decide on whether the models meet the acceptance criteria of said TP. A TP could include quantitative requirements and would need to make those publicly available to the GO under R1. The P2800.2 team has struggled to create a singular standard that is ubiquitous among all jurisdictions. However, this challenge does not present itself on a TP by TP basis.

This language has been clarified and timelines have been moved from the periodicity attachment to the main body of the requirement. The excursion criteria was defined under the currently effective MOD-27-1 standard and the DT did not see a need to remove it from the new version of the standard.

For IBRs, the testing is at the unit or inverter/converter level as described in the requirement. As where for other devices such as statcoms and SVCs, the unit level is the facility level. The footnote also defines what is meant by an IBR Unit.

The TPs response time is 90 days not 120 days, and the response time is to ensure that the TP has time to review the GO's submittal, gather any technical data if needed, and send it back to the GO's. OR if the model is acceptable, then they would accept the model within the 90 day period. The intent to have the TP decide on the acceptability criteria is to ensure an open and transparent process for the GO. There were many comments from industry that the GO's did not always know how or what they needed to submit. The purpose here is to formalize that process, ensure transparency, and increase efficiency.

The GO's response time is 90 days not 120 days, and the response time is to ensure that the GO has time to review the TP's request/response, gather any technical data if needed, and send it to the TP's.

Attachment 1:
The intent of having the validation requirement in the table is to ensure it only applies to specific parts of the generator models that validation is applicable to. For example, it is not practical to validate protection and so this is left out.

For Attachment 2 and Technical Rationale the changes will be adopted, clarified, and added.

Elizabeth Davis - PJM Interconnection, L.L.C. - 2 - RF	
Answer	
Document Name	
Comment	

In the redline version of MOD-026-2 (page 35 of 36) MOD-026-2 Attachment 2, row number 14, the first 'OR' should be an 'AND': Commissioning date of the applicable legacy facility (before the effective date of MOD-026-2); **AND** The original equipment manufacturer (OEM) is no longer doing business in North America; without this correction, Attachment 2, row 14 conflicts with R1 legacy requirements. Also, how much time does the PC have to collect the legacy

generator data? Is it intended to be at the next 10 year cycle or are we required to collect data upon implementation? If it is the latter, there needs to be a reasonable timeline. In the redline version of MOD-026-2 (page 28 of 36) MOD-026-2 Attachment 2, row number 2, requesting to remove the 365 calendar days after the commissioning date and replace with the transmittal of the verified model and accompanying information to its TP to take place prior to commissioning. As currently written, the timing of verifying the model is excessive. New generation resources that have not yet reached their commercial operation date (COD) has caused system reliability issues in certain regions. The use of COD as a threshold at which a resource owner and operator are required to register with NERC and be subject to NERC Reliability Standards creates a gap during which the resources are online and capable of impacting system reliability but are not subject to NERC Reliability Standards. During this gap period, resources are often owned and operated by entities other than the entities who will assume ownership of and operational responsibility for the resources once they reach their COD. As written, the Standard is forcing system operators to operate for over a year with a resource and no final modeling. While addressing this gap is beyond the scope of this project, NERC should continue reviewing whether the COD remains the appropriate threshold for resource owner and operator registration and should evaluate possible options for addressing this reliability gap. Similarly, Requirement 4 and Attachment 2, row numbers 6 and 7: any changes to in-service equipment should be provided in advance of the change (not time periods or plans thereafter). Again, allowing a generator to operate with changed equipment without models representing those changes is not in the direction of goodness. As currently written, there is a 'do loop' within the process of modeling updates where the GO/TO may submit a model that is not usable and the TP provides the required response – this may be executed infinitely many times without any compliance concerns. While we understand it is not the intent of the GO/TO in submitting a model that is not usable, the process should include a practical time period for resolution, rather than a continued loop of submittals and responses. Otherwise, operations continue in an unknown state. Requirement 5: Request maintaining 'usable' language as originally written. If the SDT finds useable and not usable to also be flawed, PJM supports the use of clearer terms, such as "verified" or "denied" as they more accurately reflect the scope of the assessment conducted under the standard. Attachment 2 row numbers are missing row 5. Thank you to the Project Team for taking on this Project - most appreciated!	
Likes 0	
Dislikes 0	
Response	
Row 14 of attachment 2 has been removed and included in Requirements R1 and R3, along with Footnotes 1 and 3 to provide clarity. Under Part 1.2.1, the TP/PC shall identify which legacy facilities will require EMT models within their dynamic model requirements. Documentation of Model Verification and Model Validation is intended to capture the dynamic model representation of in-service equipment. This approach is similar to the current approach used in MOD-026-1 (Attachment 1, Row 3) and MOD-027-1 (Attachment 1, Row 4), allowing	

365 calendar days after COD. The language within MOD-026-2 Attachment 2, Row 2 has been changed from commissioning date to commercial operation date.

Documentation of Model Verification and Model Validation is intended to capture changes to the dynamic model representation of in-service equipment. This approach is similar to the current approach used in MOD-026-1 (Requirement 4) and MOD-027-1 (Requirement 4), allowing 180 calendar days after making qualifying changes.

Timeframes for compliance within the process of modeling updates have been included in Requirements R5 and R6. Within the stated timeframes, GO/TO's shall provide updated model(s) and documentation, or technical justification for maintaining the current model, addressing the unacceptable dynamic modeling requirements identified and communicated by the TP.

The DT has added the language 'acceptable' and 'not acceptable' to the standard. Acceptability is determined by the model's ability to meet the dynamic requirements developed under Requirement R1.

This omission has been corrected in the current draft version. Thank you.

Greg Davis – Georgia Transmission Corporation - 1

Answer	
Document Name	
Comment	

Regarding Requirement R1: There might be more benefit to having uniform dynamic model verification requirements. Generator owners that have facilities connected to various TP's or PC's should not be required to validate similar facilities in multiple different ways based only on the location of the facilities.

Regarding R3: R3 appears to require the TO to provide verified EMT models for Non-BES IBR, for which the TO has no authority, and to document why test results for such facilities are not available. Requiring the TO to comply with R3 for facilities of which the TO has no authority seems to only add administrative burden with little to no benefit.

Regarding the use of a Periodicity table: The use of a Periodicity table adds a level of unnecessary confusion to the standard. Forcing the reader to jump from section to section of the standard to determine what a particular requirement demands causes the reader to lose focus

of the requirement. As much as possible the SDT should minimize the need for the reader to jump from section to section to understand the demands of a particular requirement. The Periodicity table is broken down by facility type/modeling condition, and by requirement. We recommend that the SDT eliminate the Periodicity Table and state the period within the requirement, adding sub-requirements for each facility type/modeling condition as needed.	
Likes 0	
Dislikes 0	
Response	
The DT has removed language around the inclusion of MOD-032-2 and has included language to list what is needed in the model for facility and unit level Model Valdiation and Model Verification. Requirment R3 and this standard only require Model Validation and Model Verification of registered IBRs and Sychnronous generation. Yes, this extends pasted the BES to the BPS as seen in the facility section 4.2.6, but there are no non registered IBRs included in this standard. The periodicity table was in the version 1 standards, it helps add a level clarity to the standard that can not be incorporated in the body of the language. The DT has refined the table and removed multiple rows to simply it to be more clear and concise.	